Final Report

BART Analysis for Apache Generating Station Steam Unit 1

Prepared for

AEPCO

Prepared by

CH2MHILL

December 2007

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Executive Summary

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Background

In response to the Regional Haze Rule and Best Available Retrofit Technology (BART) regulations and guidelines, Arizona Electric Power Cooperative (AEPCO) requested that CH2M HILL perform a BART analysis for Apache Generating Station Steam Unit 1 (hereafter referred to as ST1). AEPCO's Apache Generating Station facilities include seven electric generating units, one of which is a 75-megawatt (MW) natural gas- and oil-fired steam electric generating unit. The BART analysis for ST1 addressed the following criteria pollutants: nitrogen oxides (NO_x) sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}). BART emissions limits must be achieved within 5 years after the State Implementation Plan (SIP) is approved by the United States Environmental Protection Agency (EPA). A compliance date of 2013 was assumed for this analysis.

In completing the BART analysis, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified. The following technology alternatives were investigated, listed below by pollutant:

- AEPCO NO_x emission controls:
  - Low-NO_x burners (LNB) burners with over-fire air (OFA)
  - Flue Gas Recirculation (FGR)
  - Rotating opposed fire air (ROFA)
  - Neural Net Controls
  - LNBs with selective non-catalytic reduction system (SNCR and Rotamix)
  - LNBs with selective catalytic reduction (SCR) system
- SO_2 emission controls:
  - Use of low-sulfur distillate fuels
  - Switch to pipeline natural gas (PNG)
  - New Spray Dryer Absorber (SDA) system
- PM_{10} emission controls:
  - Use of low sulfur fuel oil (No. 2 fuel oil)
  - Switch to PNG
  - New LNB/particulate matter burner
  - Dry electrostatic precipitator (ESP)
  - Wet ESP
  - Fabric filter

BART Engineering Analysis

The specific components of a BART engineering analysis are identified in the *Code of Federal Regulations* (CFR) at 40 CFR 51 Appendix Y, Section IV. The evaluation must include the following:

1. The identification of available, technically feasible, retrofit control options
2. Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)

3. The costs of compliance with the control options
4. The remaining useful life of the facility
5. The energy and non-air quality environmental impacts of compliance
6. The degree of visibility improvement that may reasonably be anticipated from the use of BART

These components are incorporated into the BART analysis performed by CH2M HILL through the following steps:

- **Step 1—Identify all available retrofit control technologies**
- **Step 2—Eliminate technically infeasible options**
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- **Step 3—Evaluate control effectiveness of remaining control technologies**
- **Step 4—Evaluate impacts and document the results**
  - The costs of compliance with the control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance
- **Step 5—Evaluate visibility impacts**
  - The degree of visibility improvement that may reasonably be anticipated from the use of BART

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analyses are in 2007 dollars, and costs have not been escalated to the assumed 2013 BART implementation date.

Fuel Characteristics

Under AEPCO's current Class I air quality operating permit for Apache Station, ST1 is permitted to burn PNG and Nos. 2 through 6 fuel oils. Co-firing of PNG and fuel oil is also permitted.

The BART analysis has examined only operating scenarios involving 100 percent use of PNG or 100 percent use of either fuel oil No. 2 or fuel oil No. 6. No co-firing or blended-fuel alternatives have been reviewed. The BART analysis has considered the higher nitrogen content and different combustion characteristics of fuel oil as compared to PNG used at ST1 and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

Recommendations

NO_x Emission Control

There is no BART presumptive NO_x limit assigned by EPA for wall-fired boilers burning PNG or fuel oil. Based on the analysis conducted, LNBs with FGR is recommended as BART for ST1. This selection is based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts.

SO_2 Emission Control

There is no BART-presumptive SO_2 limit assigned by the EPA for wall-fired boilers burning pipeline natural gas or fuel oil. Based on the analysis conducted, use of PNG or low-sulfur fuel oil (No. 2 fuel oil) is recommended as BART for ST1. This selection is based on the significant reduction in SO_2 emissions resulting from use of these fuels.

PM_{10} Emission Control

There is no BART-presumptive particulate matter limit assigned by the EPA for wall-fired boilers burning pipeline natural gas or fuel oil. Based on the analysis conducted, use of PNG or No. 2 fuel oil is recommended as BART for ST1, based on the significant reduction in PM_{10} emissions resulting from use of these fuels.

BART Modeling Analysis

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from ST1 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers, but less than 300 kilometers, from the Apache Generating Station. The Pine Mountain Wilderness Area (WA) has also been included on the list of potentially affected Class 1 areas because it is located just outside of the 300 kilometer radius from the Apache Plant.

The Class I areas include the following:

- Chiricahua National Monument (NM)
- Galiuro WA
- Gila WA
- Superstition WA
- Mount Baldy WA
- Sierra Ancha WA
- Pine Mountain WA
- Mazatzal WA
- Saguaro National Park (NP)

Seven post control atmospheric dispersion modeling scenarios have been developed to cover the range of effectiveness for combining the individual control technologies included in the evaluation. These modeling scenarios, and the controls assumed, are as follows:

Modeling Scenarios:

- Scenario 1: New LNB with FGR and No. 6 fuel oil
- Scenario 2: ROFA modifications with No. 6 fuel oil
- Scenario 3: ROFA Modifications and Rotamix with No. 6 fuel oil
- Scenario 4: New LNB with No. 6 fuel oil and SNCR
- Scenario 5: New LNB with No. 6 fuel oil and SCR
- Scenario 6: Fabric Filter/SDA
- Scenario 7: Fabric Filter

Visibility improvements for all emission control scenarios have been analyzed, and the results have been compared using a least-cost envelope analysis, as outlined in the draft EPA (1990) *New Source Review Workshop Manual.*

Least-Cost Envelope Analysis

The EPA has adopted the Least-Cost Envelope Analysis Methodology as an accepted methodology for selecting the most reasonable, cost-effective controls. Incremental cost-effectiveness comparisons focus on annualized cost and emission reduction differences between dominant alternatives. The dominant set of control alternatives is determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reduction for all control alternatives identified in the BART analysis.

To evaluate the impacts of the modeled control scenarios on the nine Class I areas, the total annualized cost, cost per deciview (dV) reduction, and cost per reduction in number of days above 0.5 dV were analyzed. This report provides a comparison of the average incremental costs between relevant scenarios for the 9 Class I areas; the total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile delta-deciview (ΔdV) reduction.

Just-Noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate only dV differences of approximately 1.5 to 2.0 dV or more are perceptible by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person.

Contents

Appendices

Tables

Figures

Acronyms and Abbreviations

ADEQ	Arizona Department of Environmental Quality
AEPCO	Arizona Electric Power Cooperative
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CALDESK	Program to display data and results
CALMET	Meteorological data preprocessing program for CALPUFF
CALPOST	Post-processing program for calculating visibility impacts
CALPUFF	Puff dispersion model
CFR	*Code of Federal Regulations*
dV	deciview
ΔdV	delta deciview, change in deciview
ESP	electrostatic precipitator
EPA	United States Environmental Protection Agency
FLM	Federal Land Managers
Fuel NO_x	oxidation of fuel bound nitrogen
FGD	flue gas desulfurization
FGR	flue gas recirculation
f(RH)	relative humidity factors
H_2S	hydrogen sulfide
IFGR	induced flue gas recirculation
kW	kilowatts
kW-Hr	kilowatt-hour
LAER	lowest achievable emission rate
lb/MMBtu	pounds per million British Thermal Units
LCC	Lambert Conformal Conic
LNB	low-NO_x burner
LOI	loss on ignition
$\mu h/m^3$	micrograms per cubic meters
MMBtu	Million British Thermal Units
MM5	Mesoscale Meteorological Model, Version 5
MW	megawatts
NM	National Monument
NO_x	oxides of nitrogen
NP	National Park
NWS	National Weather Service

OFA	over-fire air
PNG	pipeline natural gas
$PM_{2.5}$	particulate matter less than 2.5 micrometers in aerodynamic diameter
PM_{10}	particulate matter less than 10 micrometers in aerodynamic diameter
RACT	reasonably available control technology
ROFA	Rotating Opposed Fire Air
SCR	selective catalytic reduction system
SDA	spray dryer absorber
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction system
SO_2	sulfur dioxide
Thermal NO_x	high temperature fixation of atmospheric nitrogen in combustion air
USGS	U.S. Geological Survey
WA	Wilderness Area
WRAP	Western Regional Air Partnership

Section 1.0
Introduction

1.0 Introduction

The Clean Air Act established goals for visibility improvement in national parks (NPs), wilderness areas (WAs), and international parks. Through the 1977 amendments to the Clean Air Act in Section 169A, Congress set a national goal for visibility as "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." The Amendments required the United States Environmental Protection Agency (EPA) to issue regulations to assure "reasonable progress" toward meeting the national goal. In 1990, Congress again amended the Clean Air Act, providing additional emphasis on regional haze issues.

In 1999, the NPs and WAs across the country classified as mandatory Class I areas. These regulations include requirements for states to establish goals for improving visibility in NPs and WAs and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment.

One of the principal elements of the visibility protection provisions of the Clean Air Act addresses installation of best available retrofit technology (BART) for certain existing sources placed into operation between 1962 and 1977. The 1999 Regional Haze Rule requires the following three basic state plan elements related to BART:

- A list of BART-eligible sources (includes sources of air pollutants that are reasonably anticipated to contribute to visibility impairment in a Class I area)
- An analysis of the emission reductions and changes in visibility that would result from "best retrofit" control levels on sources subject to BART
- The BART emission limits for each subject source, or an alternative measure, such as an emissions trading program for achieving greater reasonable progress in visibility protection than implementation of source-by-source BART controls

In determining BART, the state can take into account several factors, including the existing control technology in place at the source, the costs of compliance, energy and non-air environmental impacts of compliance, remaining useful life of the source, and the degree of visibility improvement that is reasonably anticipated from the use of such technology (EPA, 1999).

In July 2005, the EPA released specific BART guidelines for states to use when determining which facilities must install additional controls and the type of controls that must be used. Under current regulatory deadlines, states—including Arizona—must submit a Regional Haze Rule State Implementation Plan (SIP) amendment that addresses BART implementation by December 2007. In this plan amendment, states will identify the facilities that will have to reduce emissions under BART and then set BART emissions limits for those facilities, or identify any alternative plan for reducing visibility impairing pollutants that would achieve greater reductions than those realized from BART emissions limits (EPA, 2005).

Using information from the Western Regional Air Partnership (WRAP) and its Regional Modeling Center, the State of Arizona has identified those eligible in-state sources that are required to reduce emissions under BART and has directed those sources to complete BART analyses to identify potential reductions for emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}) that would be associated with addition of additional or new air pollution controls. This information will be included in the SIP that is due in December 2007. At this time, it is expected that Arizona's SIP will address reduction of SO_2 emissions at BART sources through an alternative measure in the form of a four-state backstop cap-and-trade program. Reduction of NO_x and PM_{10} emissions will be addressed through establishment of BART emissions limits in source operating permits.

The EPA BART guidelines state that the BART emission limits established as a result of BART analyses must be fully implemented within 5 years of EPA's approval of the SIP. For the purposes of this project, that date is assumed to be 2013.

This report documents the BART analysis that was performed on Apache Steam Unit 1 (hereafter referred to as ST1) on behalf of Arizona Electric Power Cooperative (AEPCO) by CH2M HILL. The analysis was performed for the pollutants NO_x, SO_2, and PM_{10}.

Section 2.0 of this report provides a description of the present unit operation, including a discussion of fuel used in ST1. The BART Engineering Analysis is provided in Section 3.0, by pollutant type. Section 4.0 provides the methodology and results of the BART Modeling Analysis, followed by recommendations in Section 5.0. References are provided in Section 6.0. Appendices provide additional information related to the Economic Analysis performed to support the BART Engineering Analysis and BART Protocol.

Section 2.0
Present Unit Operation

2.0 Present Unit Operation

The Apache Generating Station consists of seven electric generating units with a total generating capacity of 560 megawatts (MW). The power plant is located approximately 3 miles southeast of the town of Cochise in the Willcox Basin in Cochise County, Arizona. ST1 is a wall-fired steam electric generating unit that can burn pipeline natural gas (PNG) and No. 2 through No. 6 fuel oils. The unit typically produces up to 75 MW, but is permitted to produce up to a maximum capacity of 85 MW. Currently, there is no emissions control equipment installed on ST1.

ST1 is located adjacent to Gas Turbine #1 (GT1) at Apache Generating Station. These two units can be operated separately or in a combined cycle configuration. Typical practice is to operate these units together, and under this case GT1 exhaust is routed through the ST1 boiler. Although GT1 emissions can contribute to total emissions from the ST1 stack when the units are operated in a combined cycle configuration, only ST1 is BART eligible. Therefore, ST1 is considered a stand-alone unit for this BART analysis.

ST1 was placed in service in 1963 and is assumed to continue operation until 2021. Assuming a BART implementation date of 2013, this analysis estimates a remaining life of 8 years for ST1.

Because test data for ST1 were not available, varied assumptions were used to estimate current emissions. The current NO_x emissions level when ST1 is burning PNG is approximated by averaging the highest 75 percent load 24-hour NO_x emission levels for the year 2006 EPA Acid Rain Database, because the only fuel burned in 2006 was PNG. The higher load NO_x values were determined because higher NO_x emissions can be expected at higher unit operating loads. As a simplifying assumption, No. 2 fuel oil NO_x emissions are assumed to be equal to PNG. The No. 6 fuel oil NO_x emissions were estimated from EPA AP-42. The SO_2 emissions for PNG were also estimated from the EPA Acid Rain Database, and AP-42. PM_{10} values were determined from AP-42 calculations.

Table 2-1 lists additional unit information for this analysis.

TABLE 2-1
UNIT OPERATION AND STUDY ASSUMPTIONS
ST1

General Plant Data	
Site Elevation (feet above mean sea level)	4,193
Stack Height (feet)	157
Stack Exit Internal Diameter (feet)/Exit Area (square feet)	8.0 /50.2
Stack Exit Temperature (°F)	277
Stack Exit Velocity (feet second)	90.60
Stack Flow (actual cubic feet/minute)	272,887
Annual Unit Capacity Factor (percentage)	41
Net Unit Output (MW)[e]	85
Net Unit Heat Rate (Btu/kW-Hr)(100 percent load)	10,985
Boiler Heat Input (MMBtu/hour)(100 percent load)	1,097
Type of Boiler	Front Wall-fired
Boiler Fuel	PNG, Fuel Oil No. 2 through No. 6
Current NO_x Controls	None: Good combustion practices
NO_x Emission Rate (lb/MMBtu) (PNG)[a]	0.147
NO_x Emission Rate (lb/MMBtu) (No.6 Fuel Oil)[d]	0.301
NO_x Emission Rate (lb/MMBtu) (No.2 Fuel Oil)*	0.147

TABLE 2-1
UNIT OPERATION AND STUDY ASSUMPTIONS
ST1

General Plant Data	
Current SO_2 Controls	None
SO_2 Emission Rate (lb/MMBtu) (PNG) [a]	0.00064
SO_2 Emission Rate (lb/MMBtu) (No.6 Fuel Oil) [d]	0.906
SO_2 Emission Rate (lb/MMBtu) (No.2 Fuel Oil) [c]	0.051
Current PM10 Controls	None
PM_{10} Emission Rate (lb/MMBtu) (PNG) [b]	0.0075
PM_{10} Emission Rate (lb/MMBtu) (No.6 Fuel Oil) [b]	0.0737
PM_{10} Emission Rate (lb/MMBtu) (No.2 Fuel Oil) [b]	0.0143

NOTES:
[a] From CEM data
[b] Calculated from EPA AP-42 assuming filterable particulate equals PM10
[c] Calculated from EPA AP-42 assuming No. 2 fuel oil heating value of 140,000 Btu/gallon
[d] Calculated from EPA AP-42 assuming No. 6 fuel oil sulfur content of 0.90 percent and heating value of 156,000 Btu/gallon
[e] Based on maximum generation level as identified in Apache Station's Class I permit.

The EPA did not establish a NO_x-presumptive limit for oil- and gas-fired units, but indicates that the states should consider the installation of current combustion control technology on these units. Similarly, the EPA did not establish a presumptive BART limit for SO_2 from oil-fired units. The EPA guidelines suggest that a cost-effective SO_2 control option for oil-fired units is to consider switching to a low-sulfur fuel oil (No.2 fuel oil—0.05 percent low sulfur diesel). The EPA also stated that it was unable to find a flue gas desulfurization (FGD) application in the U.S. electric industry on an oil-fired unit.

According to 40 *Code of Federal Regulations* (CFR) Parts 72 and 75, for a gaseous fuel to qualify as "natural gas," the fuel must be either greater than or equal to 70 percent methane by volume, or must have a gross calorific value between 950 and 1,100 British thermal units (Btu) per standard cubic foot. For PNG, the hydrogen sulfide (H_2S) content must be less than or equal to 0.3 grain per 100 standard cubit feet, and H_2S must constitute at least 50 percent (by weight) of the total sulfur in the fuel.

No fuel specification was provided for No. 2 fuel oil, therefore a heating value of 140,000 Btu per gallon and a sulfur limit of 0.05 percent were assumed. Heating value for No. 6 fuel oil was assumed at 155,000 Btu per gallon, with a maximum sulfur content of 0.90 percent (per Title V permit).

AEPCO desires to maintain the PNG/fuel oil capability for future operation of ST1. Therefore, this BART analysis includes a review of PNG, No. 2 fuel oil, and No. 6 fuel oil operation. In addition, the fuel cost differential between these alternative fuel options was estimated and evaluated.

Section 3.0
BART Engineering Analysis

3.0 BART Engineering Analysis

3.1 BART Process

The specific components in a BART engineering analysis are identified in 40 CFR 51 Appendix Y, Section IV. The evaluation must include the following:

1. The identification of available, technically feasible, retrofit control options
2. Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
3. The costs of compliance with the control options
4. The remaining useful life of the facility
5. The energy and non-air quality environmental impacts of compliance
6. The degree of visibility improvement that may reasonably be anticipated from the use of BART

These components are incorporated into the BART analysis performed by CH2M HILL through the following steps:

- **Step 1—Identify all available retrofit control technologies**
- **Step 2—Eliminate technically infeasible options**
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- **Step 3—Evaluate control effectiveness of remaining control technologies**
- **Step 4—Evaluate impacts and document the results**
  - The costs of compliance with the control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance
- **Step 5 – Evaluate visibility impacts**
  - The degree of visibility improvement that may reasonably be anticipated from BART use.

In the evaluation, consideration was made of any pollution control equipment in use at the source, the costs of compliance associated with the control options, and the energy and non-air quality environmental impacts of compliance using these existing control devices. As a consequence, controls scenarios included enhancement of existing equipment, as well as addition of new control equipment.

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analysis are in 2007 dollars, and costs have not been escalated to the assumed 2013 BART implementation date.

Because ST1 currently has the capability to burn PNG or No. 2 through No. 6 fuel oils, a separate analysis will be completed for each case. The option to switch to low-sulfur fuel oil (No. 2) will be examined, as required by the BART regulations.

For ST1, baseline NO_x, SO_2, PM_{10} emissions were examined to determine whether completion of the five-step BART process is required for each of the three fuel alternatives (100 percent PNG, 100 percent No. 6 fuel oil, and 100 percent No. 2 fuel oil). To complete this analysis, a reasonably available control Technology (RACT)/best available control technology (BACT)/lowest achievable emission rate (LAER) Clearinghouse (RBLC) summary was used, in addition to a review of the BART coal presumptive limits for wall-fired boilers and engineering judgment. Even though the RBLC and BART values do not apply for PNG/oil-fired units, review of these values provides a comparative basis for selecting those fuel alternatives that should reasonably undergo BART evaluation.

Table 3-1 below is a summary of the baseline emissions for ST1.

TABLE 3-1
CURRENT ST1 BASELINE EMISSIONS

Baseline Emissions (lb/MMBtu)	PNG	No. 6 Fuel Oil	No. 2 Fuel Oil
NO_x	0.147	0.301	0.147
SO_2	0.00064	0.906	0.051
Particulate Matter	0.0075	0.0737	0.0143

Table 3-2 lists the BART-presumptive coal values for a wall-fired boiler when burning sub-bituminous coal and a range of RBLC permit limits for each of the fuels.

TABLE 3-2
PRESUMPTIVE COAL EMISSION LIMITS AND RBLC EMISSION RANGES

Emission Categories	NO_x	SO_2	Particulate Matter
Presumptive Coal Limits	0.23 [a]	0.15	0.015
RBLC Ranges			
PNG	0.02 – 0.1	0.001 – 0.01	0.004 – 0.005
Fuel Oil No. 2	0.12 – 0.15	0.06 – 0.22	0.0032 – 0.03
Fuel Oil No. 6	0.37 – 1.05	0.8 – 1.76	0.01 – 0.06

NOTES:
[a] For sub-bituminous coal
Results in lb/MMBtu

After comparing the current baseline emissions to the emissions shown in BART guidance and the RBLC database, it was determined that BART NO_x analysis was appropriate for all fuels, while SO_2 and particulate matter analysis was appropriate for only No. 6 fuel oil. Current SO_2 and particulate matter emissions for PNG and No. 2 fuel oil are within or below the comparative emissions levels from BART guidance and the RBLC database, indicating a control retrofit analysis is not warranted for these two pollutants on these two fuels. No additional reduction in emissions would be expected from installation of emissions control equipment when using these two fuels.

3.1.1 Establishing Permit Emission Levels from BART Analysis Results

As an integral part of the BART analysis process, cost and expected emission information were developed for NO_x, SO_2, and PM_{10}. This information is assembled from various sources including emission reduction equipment vendors, AEPCO operating and engineering data, and internal CH2M HILL historical information.

The level of accuracy of the cost estimate can be broadly classified as American Association of Cost Engineers (AACE) Class V or "Order of Magnitude," which can be categorized as +50 percent/-30 percent. There are several reasons for selecting this range of cost estimates to be included in the BART analysis. They are primarily a result of the difficulty in receiving detailed and accurate information from equipment vendors based on limited available data provided to the vendors. Because of the active power industry marketplace, obtaining engineering and construction information is restricted due to vendor workload. Material and construction labor costs also change rapidly in today's active economy. However, this level of cost estimate precision is adequate for comparison of control technology alternatives.

The accuracy of expected emissions may also be questionable and is also attributable to the inability to gain timely and accurate vendor information. This is exemplified by the difficulty in obtaining background information and the vendor time required to develop accurate emission projections for study purposes in comparison to their response to actual project request for proposals. Also, variance in expected emissions can be dependent upon the pollutant under consideration (i.e., particulate emissions can generally be more accurately predicted than NO_x emissions).

Therefore, when selecting emissions control technologies and establishing emission limitations in permits, consideration of variability in cost and expected emissions information must be considered.

3.1.2 BART NO_x Analysis

NO_x formation in fossil fuel-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and fuel characteristics. From the analysis completed in Section 3.2, a NO_x BART analysis will be completed for the cases when ST1 burns 100 percent PNG, 100 percent No. 6 fuel oil, and 100 percent No. 2 fuel oil.

Formation of NO_x

During combustion, NO_x forms in three different ways: thermal NO_x, fuel NO_x, and prompt NO_x. When combusting PNG, the most dominant source of NO_x is from thermal NO_x, which results from high-temperature fixation of atmospheric nitrogen in the combustion air. Because PNG generally contains small quantities of nitrogen, the overall contribution from fuel NO_x is small, while a significant amount of fuel NO_x can be generated from fuel oil combustion. A very small amount of NO_x is called "prompt" NO_x. Prompt NO_x results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Good combustion is based on the "three Ts:" time, temperature, and turbulence. If a performance requirement such as NO_x emission limits is changed, conflicts with other performance issues can result.

When adjusting air flows and distribution to lower NO_x using low-NO_x burners (LNBs) and over-fire air (OFA), original boiler design restrictions may limit the modifications that can be made and still achieve satisfactory combustion performance.

Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to ST1, including those control technologies identified as BACT or LAER by permitting agencies across the United States. A broad range of information sources has been reviewed in an effort to identify potentially applicable emission control technologies. ST1 NO_x emissions are currently controlled through the use of good combustion practices. There is no BART-presumptive NO_x level for PNG and oil-fired units.

The following potential NO_x control technology options were considered:

- New LNBs with OFA
- Flue Gas Recirculation (FGR)
- Rotating Opposed Fire Air (ROFA)
- LNBs with selective non-catalytic reduction system (SNCR and Rotamix)
- LNBs with selective catalytic reduction system (SCR)
- Neural Net Controls

Step 2: Eliminate Technically Infeasible Options

For ST1, a front wall-fired configuration burning PNG and fuel oil, technical feasibility will primarily be determined by physical constraints, boiler configuration, and on the ability of the technology to achieve significant NO_x emissions reduction. Current NO_x emissions for ST1 were shown in Table 2-1.

For this BART analysis, information pertaining to LNB and FGR was based on information received from Coen for new LNBs. Coen made the assumption that the GT1 exhaust into the windbox of ST1 during combined cycle operation would be of sufficient quantity to achieve 15 percent FGR. No OFA estimate was received from Coen; however, an FGR option was presented. Cost estimates include cost for both LNB and FGR, but FGR as an additional control installation may not be necessary if AEPCO continues to rely on GT1 exhaust gas to provide FGR to ST1.

The cost estimates for SCR and SNCR were updated from previous CH2M HILL file information. CH2M HILL also received information from Mobotec for their ROFA and Rotamix technologies.

Table 3-3 summarizes the control technology options evaluated in this BART analysis, along with projected NO_x emission rates. While many of the projected emission rates shown are very low, they were estimated based on preliminary information and the basis of percentage reduction from baseline emissions. Operation at these emission levels may not be consistently achievable.

TABLE 3-3
NO_x CONTROL TECHNOLOGY EMISSION RATE RANKING
ST1

Technology	Source of Estimated Emissions	Estimated Emission Rate [d] (PNG)	Estimated Emission Rate (No. 6 Fuel Oil) [d]	Estimated Emission Rate (No. 2 Fuel Oil) [d]
Presumptive BART Limit	–	–	–	–
LNB with FGR [e]	Coen	0.056	0.15	0.06
ROFA [b]	Mobotec	0.08	0.16	0.08
ROFA with Rotamix [b]	Mobotec	0.06	0.11	0.06
LNB with FGR SNCR	Coen and Fuel Tech	0.06 [c]	0.11 [c]	0.05 [c]
SCR [a]	CH2M HILL	0.07	0.07	0.07

NOTES:
[a] SCR estimated NO_x emissions rate is the same for all scenarios. Operating cost would be affected by inlet NO_x levels.
[b] Calculated from Mobotec proposal information fuel baselines (47 percent reduction for ROFA and additional 30 percent for Rotamix)
[c] From Previous Fuel Tech Proposal at 25 percent reduction
[d] Results are in lb/MMBtu
[e] From Coen Proposal

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Preliminary vendor proposals, such as those used to support portions of this BART analysis, may be technically feasible and provide expected or guaranteed emission rates; however, they include inherent uncertainties. These proposals are usually prepared in a limited time frame, may be based on incomplete information, may contain overly optimistic conclusions, and are non-binding. Therefore, emission rate values obtained in such preliminary proposals must be qualified, and it must be recognized that contractual guarantees are established only after more detailed analysis has been completed. The following subsections describe the control technologies and the control effectiveness evaluated in this BART analysis.

Level of Confidence for Vendor Post-Control Emissions Estimates. To determine the level of NO_x emissions needed to achieve compliance consistently with an established goal, a review of typical NO_x emissions from fossil fuel-fired generating units was completed. As a result of this review, it was noted that NO_x emissions can vary significantly around an average emissions level. This variance can be attributed to many reasons, including fuel characteristics, unit load, boiler operation including excess air, burner equipment condition, and so forth.

The steps used to determine a level of confidence for the vendor expected value are as follows:

1. Establish expected NO_x emissions value from vendor.
2. Evaluate vendor experience and historical basis for meeting expected values.
3. Review and evaluate unit physical and operational characteristics and restrictions. The fewer variations there are in operations, fuel supply, etc., the more predictable and less variable the NO_x emissions are.
4. For each technology expected value, there is a corresponding potential for actual NO_x emissions to vary from this expected value. From the vendor information presented, along with anticipated unit operational data, an adjustment to the expected value can be made.

The following subsections describe the control technologies and the control effectiveness evaluated in this BART analysis.

New LNBs with OFA System. The mechanism used to lower NO_x with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to nitrogen instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

Both LNBs and OFA are considered to be a capital cost, combustion technology retrofit that may require water wall tube replacement.

FGR. FGR generally extracts flue gas from downstream of the economizer or air heater and is mixed into the combustion air duct. This recirculation can be achieved with a new FGR fan or by using the existing forced-draft fan to inject the flue gas into the combustion air (induced flue gas recirculation [IFGR]). Flue gas recirculation adds oxygen-lean heat-absorbing mass to the combustion air, thus lowering the combustion temperature and reducing NO_x emissions.

ROFA. Mobotec markets ROFA as an improved second-generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively." A typical ROFA installation will have a booster fan(s) to supply the high velocity air to the ROFA boxes. Mobotec would propose one 700 horsepower fan for ST1.

Mobotec's budgetary proposals included expected NO_x emission rates for PNG and No. 2 and No. 2 fuel oils, and are presented in Table 3-3. While a typical installation does not require modifying an installed LNB system, and the existing OFA ports are not used, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. Although not specifically identified, Mobotec generally includes bent tube assemblies for OFA port installation if required. Mobotec does not provide installation services, because they believe that the owner can more cost-effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

SNCR. SNCR is generally used to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low-reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia may render fly ash unsolvable, react with sulfur to foul heat exchange surfaces, or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_x) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption. Budgetary proposals were received from Mobotec for their Rotamix system, and previous Fuel Tech proposal information for other projects was used.

SCR. SCR works on the same chemical principle as SNCR but SCR uses a catalyst to promote the chemical reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F and 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_x emissions. The most common type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of particulate in the flue gas that is leaving the boiler. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher removal rate, a full-scale SCR was used as the basis for analysis at ST1. From previous SCR design experience, a projected NO_x emission rate of 0.07 pounds per million British thermal units (lb/MMBtu) is projected for all emissions control equipment scenarios.

Neural Net Controls

Information regarding neural net controls was received from NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NO_x reduction. NeuCo stated that these products can be used on most control systems and can be effective even in conjunction with other NO_x reduction technologies.

NeuCo predicts that CombustionOpt can reduce NO_x by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes. The budgetary prices for CombustionOpt and SootOpt were $150,000 and $175,000, respectively, with an additional $200,000 for a process link to the unit control system.

Because NeuCo does not guarantee NO_x reduction, the estimated emission reduction levels provided cannot be considered as reliable projections. Therefore, neural net should be considered as a supplementary or "polishing" technology, but not on a "stand-alone" basis.

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Installation of LNBs is not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies will not have energy impacts.

The Mobotec ROFA system requires installation and operation of one 700 horsepower ROFA fan (522 kilowatts [kW] total). An estimated auxiliary power requirement for an SNCR system for an 85-MW (with the 10-MW combustion turbine included) unit is estimated at 85 kW. The same estimate was used for Rotamix.

SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

Environmental Impacts. SNCR and SCR installation could potentially create a visible stack plume from excess ammonia slip, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

Economic Impacts. Costs and emissions estimates for the LNBs, SNCR, and SCR were obtained from equipment vendors. Costs for the ROFA and Rotamix systems were obtained from Mobotec.

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-4, and the first year control costs in Figure 3-1. The complete Economic Analysis is contained in Appendix A.

The capital costs shown in Table 3-4 are applicable for all of the fuels under consideration, and No. 6 fuel oil was used as the basis to determine worst-case emission levels. For example, if LNBs are installed for PNG, the burner costs include the capability to burn both PNG and No. 2 and 6 fuel oils (with only minor equipment modification, atomization changes, and burner control revisions). Similarly, the cost information for any of the NO_x reduction technologies listed in Table 3-4 will apply for the fuel alternatives under consideration. Costs for LNBs are presented with FGR because this scenario is representative of current operation of ST1 when it is operated in combined cycle with GT1. Costs for LNBs without FGR would be lower.

Preliminary BART Selection. The four-step evaluation indicates new LNBs with FGR would represent BART for ST1 based on its significant reduction in NO_x emissions, reasonable control cost, and no additional power requirements or environmental impacts. Consideration could also be given to LNBs as a stand-alone technology without FGR, but because it is common for ST1 to obtain FGR due to combined cycle operation with GT1, considering LNBs in combination with FGR is a more representative control scenario for ST1 than use of LNBs alone.

Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

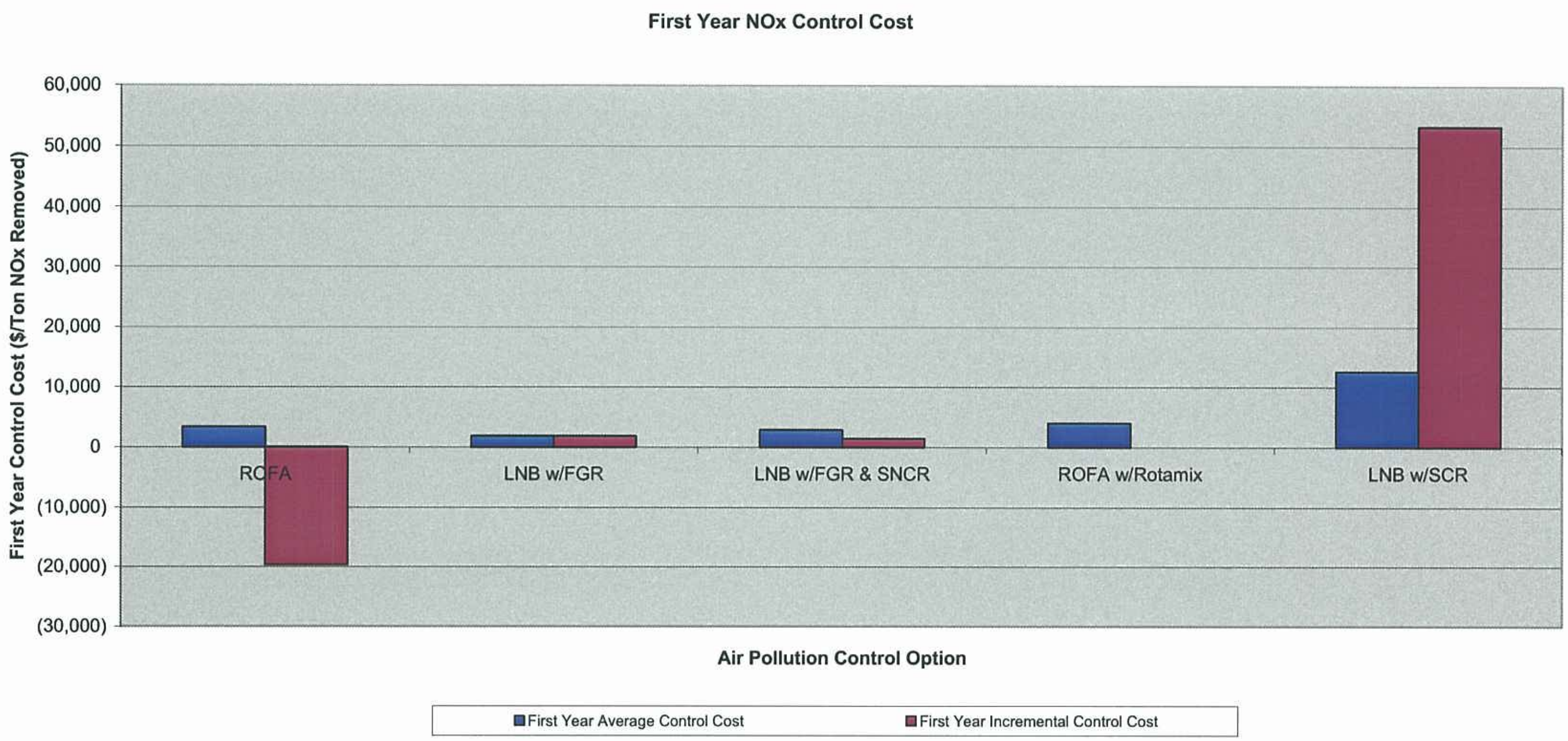
TABLE 3-4

NO_X CONTROL COST COMPARISON
ST1

Factor	ROFA [c]	LNB with FGR	LNB with FGR and SNCR [b]	ROFA with Rotamix	LNB with SCR [a]
Total Installed Capital Costs	$2,700,000	$1,184,000	$4,584,000	$4,457,000	$25,500,000
Total Installed Capital Costs with Additional Owner Costs	$4,725,000	$2,072,000	$5,730,000	$7,799,750	$31,875,000
Total First Year Fixed and Variable O&M Costs	$144,739	$203,643	$116,077	$194,552	$346,058
Total First Year Annualized Cost	$939,093	$551,982	$1,079,389	$1,505,825	$5,704,798
Power Consumption (MW)	0.52	0.85	0.09	0.52	0.43
Annual Power Usage (Million kW-Hr/ Year)	1.9	3.1	0.3	1.9	1.5
NO_x Design Control Efficiency	46.8%	50.2%	63.5%	63.5%	76.7%
Tons NO_x Removed per Year	278	297	376	376	455
First Year Ave Control Cost ($/Ton NO_x Removed)	3,382	1,856	2,870	4,004	12,542
Incremental Control Cost ($/Ton NO_x Removed)	(19,659)	1,856	1,425	— [d]	53,311

NOTES:
[a] Based on $300 per kW SCR factored estimate for 85 megawatts
[b] Based on $40 per kW SNCR factored estimate for 85 megawatts
[c] ROFA has a negative incremental control cost because when compared with LNB with FGR the technology costs more and removes less tons of NO_x
[d] The incremental control cost for ROFA with Rotamix when compared with LNB with FGR and SNCR results in a non number as the two technologies have the same NO_x removal in tons per year

FIGURE 3-1
First Year Control Cost for NOx Air Pollution Control Options
ST1



3.1.3 BART SO_2 Analysis

SO_2 forms in the boiler during the combustion process and is primarily dependent on natural gas and fuel oil sulfur content. The BART analysis for SO_2 emissions on ST1 follows. From the analysis completed in Section 3.2, SO_2 emissions indicate that BART analysis is not required when ST1 burns PNG or fuel oil No. 2. Thus, the analysis in this section is limited to the case when ST1 is burning No. 6 fuel oil.

The EPA BART guidelines require that oil-fired units consider limiting the sulfur content of the fuel oil burned. Because current requirements for low-sulfur diesel fuel limit sulfur content to 0.05 percent, fuel switching will be analyzed as an SO_2 option for this study. Also, a dry FGD system with similar SO_2 reduction capability as the fuel switch option will be considered.

Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources was reviewed in an effort to identify potentially applicable emission control technologies for SO_2 at ST1. As discussed in Section 3.2, this included control technologies identified as BACT or LAER by permitting agencies across the United States.

Following elimination of the PNG and fuel oil No. 2 BART engineering analysis after RLBC database review, the following potential SO_2 control technology options were considered for application when ST1 burns fuel oil No. 6:

- Use of low-sulfur distillate oil (No. 2 fuel oil)
- Switch to PNG
- Spray dryer absorber (SDA)

Step 2: Eliminate Technically Infeasible Options

Technical feasibility will primarily be determined by fuel storage delivery constraints, boiler configuration, and the ability of low-sulfur fuel oil to achieve significant SO_2 emission reduction. The present SO_2 emission rate for ST1 while burning No. 6 fuel oil is estimated at 0.906 lb/MMBtu.

Table 3-5 summarizes the control technology options evaluated in this BART analysis, along with projected SO_2 emission rates while burning No. 6 fuel oil. The estimated cost does not include fuel cost differential.

TABLE 3-5
CONTROL TECHNOLOGY OPTIONS EVALUATED
ST1

Technology	Expected Emission Rate (lb/MMBtu)	Estimated Cost (Millions $)
Current Baseline with No. 6 Fuel Oil	0.906	–
Low-Sulfur Fuel Oil	0.051	0
SDA	0.10	20
PNG	0.00064	0

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. One such benchmark is the presumptive BART emission limit for coal-fired units (0.15 lb/MMBtu), even though as a PNG/fuel oil-fired unit, ST1 is not required to meet this limit. With a fuel switch to low-sulfur diesel, the expected SO_2 emissions are estimated at 0.051 lb/MMBtu, and an SDA is estimated to achieve approximately a 0.10 lb/MMBtu emission rate.

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. There is no energy impact associated with switching to low-sulfur diesel fuel; however, additional system pressure drop equivalent to 0.4 MW at a first-year cost of $71,832 will result from the installation of an SDA.

Environmental Impacts. There is no environmental impact associated with switching to low-sulfur diesel fuel. An SDA system generates solid waste requiring disposal.

Economic Impacts. A summary of the costs and amount of SO_2 removed for fuel switching is provided in Table 3-6. The complete Economic Analysis is contained in Appendix A.

TABLE 3-6

SO_2 CONTROL COST
ST1

Factor	SDA	Switch to PNG	Switch to Low-Sulfur Fuel
Total Installed Capital Costs	$20,000,000 [a]	$0	$0
Total First Year Fixed & Variable Operations & Maintenance Costs	$519,359	–	–
Total First Year Annualized Cost	$3,881,706	–	–
Power Consumption (MW)	0.40	–	–
Annual Power Usage (kW-Hr/Year)	1.4	–	–
SO_2 Design Control Efficiency	89.0%	99.9%	91%
Tons SO_2 Removed per Year	1,587	–	–
First Year Average Control Cost ($/Ton of SO_2 Removed)	2,446	–	–
Incremental Control Cost ($/Ton of SO_2 Removed)	2,446	–	–

[a] Based on vendor cost information

Preliminary BART Selection. The four-step evaluation indicates that using PNG or low-sulfur diesel fuel (No. 2 fuel oil) would represent BART for ST1 based on significant reduction in SO_2 emissions reasonable control costs and the advantages of no additional power requirements or environmental impacts. While burning solely PNG will result in the greatest NO_x reduction at the lowest cost, the requirement for dual-fuel capability dictates the use of fuel oil as a secondary fuel. While the installation of an SDA will achieve SO_2 significant emission reductions, switching to No. 2 fuel oil or burning PNG offers greater potential for lower SO_2 levels with no capital cost requirements.

Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

3.1.4 BART PM_{10} Analysis

The BART analysis for PM_{10} emissions at ST1 is described below. From the analysis completed in Section 3.2, a PM_{10} BART analysis will only be completed for the case when ST1 burns 100 percent No. 6 fuel oil. The current baseline particulate matter/PM_{10} emissions, while burning PNG or No. 2 fuel oil, already meets the BACT emissions level.

Step 1: Identify All Available Retrofit Control Technologies

The following retrofit control technologies have been identified for PM_{10} control on ST1:

- Use of low-sulfur fuel oil (No. 2 fuel oil)
- Switch to PNG
- New LNBs/particulate matter burner
- Dry electrostatic precipitator (ESP)
- Wet ESP
- Fabric filter

Step 2: Eliminate Technically Infeasible Options

Low Sulfur Distillate Oil. Particulate matter emissions would be reduced with the switching of fuel oil grades from No. 6 to No. 2. As discussed in Section 3.2, anticipated PM_{10} emissions while burning No. 2 fuel oil are estimated at 0.0143 lb/MMBtu.

Switch to PNG. Expected PM_{10} emissions when burning PNG are estimated at 0.0075 lb/MMBtu.

New LNBs/Particulate Matter Burner. With the Coen LNB, particulate matter emissions are also reduced. From the budgetary information received from Coen, particulate matter emissions are estimated at less than 0.03 lb/MMBtu and 0.0015 lb/MMBtu while burning No. 6 fuel oil (with LNB and IFGR), and No. 2 fuel oil (LNB), respectively.

Dry ESP. A dry ESP operates by first placing a charge on the particulates though a series of electrodes, and then capturing the charged particulates on collection plates. While an ESP can be designed for high-particulate removal, operation is susceptible to particle resistivity, which denotes a collected particle's ability to ultimately discharge to the collection plate. Low-resistivity particles can be easily charged but may quickly lose their charge at the collection plate and tend to be re-entrained into the flue gas stream. Higher resistivity particles may form a "back corona," which is caused by a layer of non-conductive particles being formed on the collection plate. Back corona may prevent other charged gas stream particles from migrating to the collection plate. Particle resistivity is also influenced by flue gas temperature. ESP sizing is in large part determined by particulate size, with larger ESP size required when smaller particulates are expected. In addition, the particulates from an oil-fired unit tend to be small and sticky, and if an SDA is used for SO_2 reduction, there will be a greatly increased inlet particulate loading to the ESP.

Because of the uncertainty in chemical and physical characteristics of the oil-fired particulate, a dry ESP is not a good technological match for ST1.

Wet ESP. While wet ESP operation is similar to the dry ESP through the charging and collection of flue gas particulates, the wet technology has significant advantages. The wet ESP is not sensitive to particulate resistivity and can accommodate changes in particulate loading more easily than a dry ESP. Collection plates can be fabricated from metal or fabric, and the collected particulate is washed off the plates with water.

Wet ESPs have successfully been demonstrated on similar oil particulate or chemical mist applications. However, flue gas leaving the wet ESP will be saturated and may result in a visual steam plume exiting the stack. The wet ESP will use water to collect and remove the particulates, and will produce a wastewater byproduct.

While the wet ESP PM_{10} emission level is estimated to be similar to a fabric filter without SDA operation, increased particulate loading from an SDA may not allow a wet ESP to meet required collection efficiency. Therefore, a wet ESP is not a technically acceptable alternative when matched with an SDA.

Fabric Filter. Fabric filter technology achieves particulate reduction through the filtration of the flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse jet or reverse flow mechanism. A pulse jet filtration system would likely be selected for installation on ST1, because this fabric filter technology results in lower capital cost and a smaller required footprint.

Because of the somewhat sticky particles produced during oil firing, appropriate fabric or coating bags with a suitable pre-coat material are imperative. If fabric bags become "blinded" by allowing hard-to-remove particulates to become embedded in the fabric structure, total bag replacement may be necessary. Blinded bags will continue to provide excellent filtration efficiencies; however, the pressure drop across the fabric may exceed system draft capability.

While a fabric filter is not an acceptable alternative for particulate matter/PM_{10} emissions control for an oil-fired unit without using a coating material, it is anticipated to function satisfactorily with a pre-coat and the increased particulate loading from the SDA operation.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

ST1 particulate matter emissions are currently estimated at 0.0737 lb/MMBtu while burning No. 6 fuel oil. From the RBLC review completed in Section 3.2, the BART PM_{10} analysis will be completed only for the case of firing 100 percent No. 6 fuel oil.

The PM_{10} control technology emission rates are summarized in Table 3-7. No capital costs are associated with switching to PNG.

TABLE 3-7
PM_{10} CONTROL TECHNOLOGY EMISSION RATES
ST1

Control Technology	Expected PM_{10} Emission Rate (lb/MMBtu)
Current Baseline	0.0737
Fabric Filter	0.015
New LNB [a]	0.0015
Switch to PNG	0.0075

NOTES:
[a] When burning No. 2 fuel oil

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. No additional energy impact is expected from PM_{10} reduction as a result of a new LNBs/particulate matter burner retrofit or burning of low-sulfur fuel oil. A fabric filter and ductwork will add an estimated 6 to 8 inches of water pressure drop to the system and additional electrical load requirements.

Environmental Impacts. There are no negative environmental impacts from the usage of new LNBs/particulate matter burners, switching to low-sulfur diesel fuel, or using a fabric filter.

Economic Impacts. A summary of the costs and particulate matter removed for the alternatives is recorded in Table 3-8. The complete Economic Analysis is contained in Appendix A.

TABLE 3-8
PARTICULATE MATTER CONTROL COST COMPARISON*
ST1

Factor	Fabric Filter	Switch to PNG	Switch to Low-Sulfur Fuel
Total Installed Capital Costs	$20,000,000 [a]	$0	$1,000,000 [b]
Total First Year Fixed and Variable O&M Costs	$253,592	–	–
Total First Year Annualized Cost	$3,615,938	–	–
Power Consumption (MW)	0.40	–	–
Annual Power Usage (Million kW-Hr/Year)	1.4	–	–
Particulate Matter Design Control Efficiency	79.6%	–	–
Tons Particulate Matter Removed per Year	116	–	–
First Year Ave Control Cost ($/Ton of Particulate Matter Removed)	24,916	–	–
Incremental Control Cost ($/Ton Particulate Matter Removed)	31,284	–	–

NOTES:
LNB costs included in Section 3.1.1
[a] Based on vendor cost information
[b] From CH2M HILL database

Preliminary BART Selection. The four-step evaluation indicates that using PNG or low-sulfur fuel oil would represent BART for ST1 based on its significant reduction in PM_{10} emissions, no additional control cost, and no environmental impacts. Although the installation of a fabric filter would achieve acceptable PM_{10} emission levels while burning No. 6 fuel oil, a significant capital expenditure is required.

Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

3.2 Summary

The most cost-effective emissions control scenario includes using PNG as fuel and the installation of LNB with FGR (which will also burn fuel oil with minor equipment change out). Because AEPCO desires a backup secondary fuel, No. 2 fuel oil can also be burned with an LNB installation. No. 6 fuel oil may be used if an SDA and fabric filter are installed for SO_2 and PM_{10} emissions reduction, respectively, in addition to an LNB upgrade.

Section 4.0
BART Modeling Analysis

4.0 BART Modeling Analysis

4.1 Introduction

This section presents the dispersion modeling methods and results for estimating the degree of visibility improvement from BART control technology options for the AEPCO ST1.

To a large extent, the modeling followed the methodology outlined in the WRAP protocol for performing BART analyses (WRAP, 2006). Any proposed deviations from that methodology are documented in this report.

4.2 Model Selection

CH2M HILL used the EPA-required CALPUFF modeling system to assess the visibility impacts at Class I areas. CALPUFF is a multi-layer, multi-species non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on pollution transport, transformation and removal. BART guidance says, "CALPUFF is the best regulatory modeling application currently available for predicting a single source's contribution to visibility impairment and is currently the only EPA-approved model for use in estimating single source pollutant concentrations resulting from the long range transport of pollutants."

The CALPUFF modeling system includes the meteorological data pre-processing program for CALPUFF (CALMET) with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode.

CH2M HILL used the latest version (Version 6) of the CALPUFF modeling system preprocessors and models in lieu of the EPA-approved versions (Version 5). The FLM and others have noted that the EPA-approved Version 5 contained errors and that a newer version should be used. Consequently, it was decided to use the latest (as of April 2006) version of the CALPUFF modeling system (available at www.src.com):

- CALMET Version 6.211 Level 060414
- CALPUFF Version 6.112 Level 060412

CALMET, CALPUFF, CALPOST, and POSTUTIL were recompiled with the Lahey/Fujitsu Fortran 95 Compiler (Release 7.10.02) to accommodate the large CALMET domain. The recompiled processors were tested against the test case results provided with the source code (TRC, 2007), and the difference between the results was 0.03 percent.

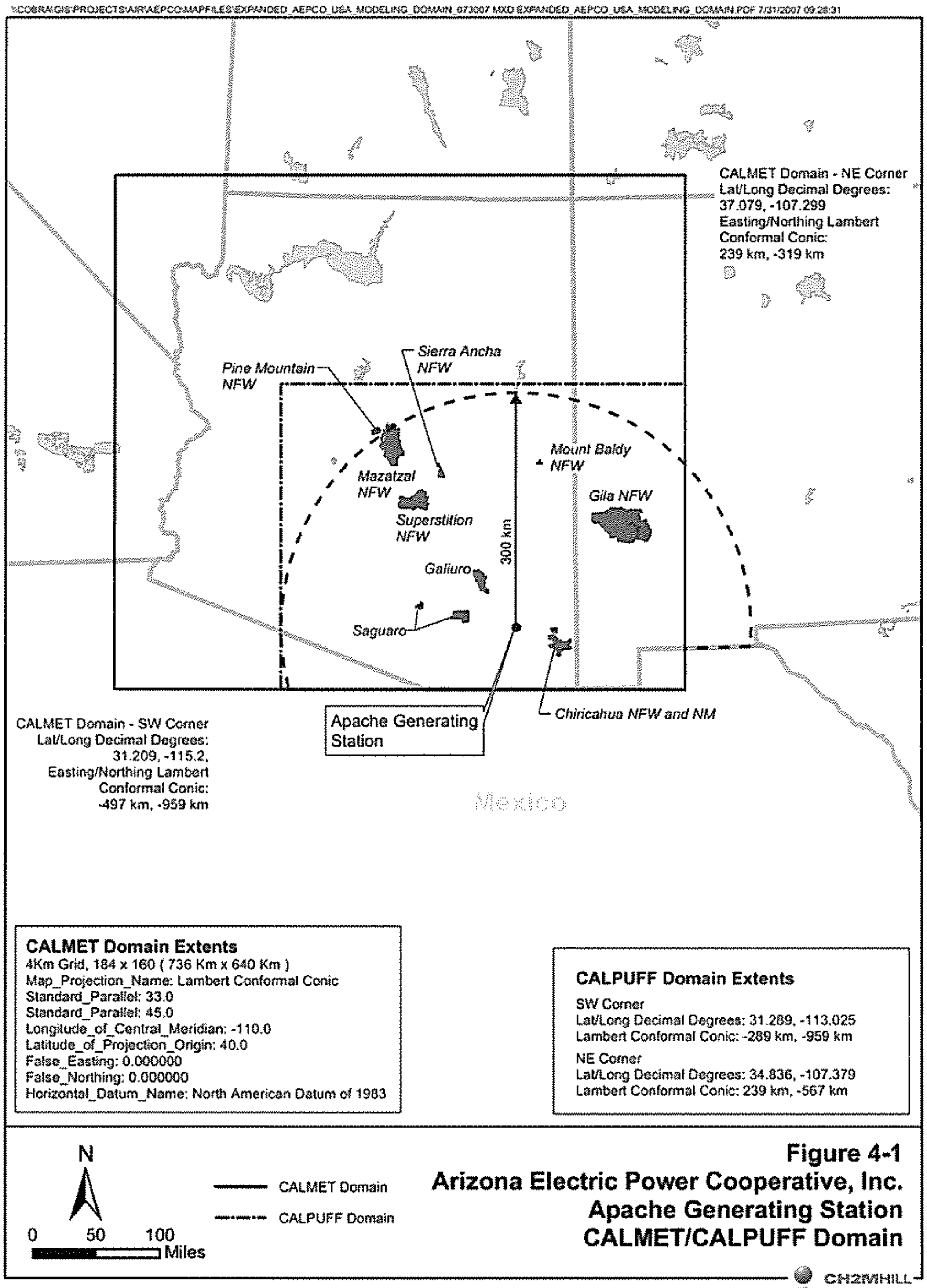
4.3 CALMET Methodology

4.3.1 Dimensions of the Modeling Domain

CH2M HILL defined domains for Mesoscale Meteorological Model, Version 5 (MM5), CALMET, and CALPUFF that were slightly different than those established for the Arizona BART modeling in WRAP (2006). In addition, the CALMET and CALPUFF Lambert Conformal Conic (LCC) map projection used in this analysis is based on a central meridian of 110° W rather than 97° W. This puts the central meridian near the center of the domain.

CH2M HILL used the CALMET model to generate three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. A CALMET modeling domain has been defined to allow for at least a 50-kilometer buffer around all Class I areas within 300 kilometers of the Apache Power Plant. Grid resolution for this domain was 4 kilometers. Figure 4-1 shows the extent of the modeling domain.

FIGURE 4-1
CALPUFF and CALMET Modeling Domains



The technical options recommended in WRAP (2006) were used for CALMET. Vertical resolution of the wind field included 11 layers, with vertical cell face heights as follows (in meters):

- 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 5000

Also, following WRAP (2006), ZIMAX were set to 4,500 meters based on the Colorado Department of Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (CDPHE, 2005). The CDPHE analysis suggests mixing heights in the Denver area are often well above the CALMET default value of 3,000 meters during the summer. For example, on some summer days, ozone levels are elevated to 6,000 meters mean sea level or beyond during some meteorological regimes, including some regimes associated with high-ozone episodes. It is assumed that, as in Denver, mixing heights in excess of the 3,000 meters AGL CALMET default maximum would occur in the domain used for this analysis.

Table 4-1 lists the key user-specified options.

TABLE 4-1
USER-SPECIFIED CALMET OPTIONS

Description	CALMET Input Parameter	Value
	CALMET Input Group 2	
Map projection	PMAP	LCC
Grid spacing	DGRIDKM	4
Number vertical layers	NZ	11
Top of lowest layer (meters)		20
Top of highest layer (meters)		5,000
	CALMET Input Group 4	
Observation mode	NOOBS	1
	CALMET Input Group 5	
Extrapolation of surface wind observations	IEXTRP	4
Prognostic or MM-FDDA data switch	IPROG	14
Max surface over-land extrapolation radius (kilometers)	RMAX1	50
Max aloft over-land extrapolations radius (kilometers)	RMAX2	50
Radius of influence of terrain features (kilometers)	TERRAD	10
Relative weight at surface of Step 1 field and obs	R1	25
Relative weight aloft of Step 1 field and obs	R2	25
	CALMET Input Group 6	
Maximum over-land mixing height (meters)	ZIMAX	4,500

4.3.2 CALMET Input Data

CH2M HILL ran the CALMET model to produce 3 years of analysis: 2001, 2002, and 2003. CH2M HILL used MM5 data as the basis for the CALMET wind fields. The horizontal resolution of the MM5 data is 36 kilometers.

For 2001, CH2M HILL used MM5 data at 36-kilometers resolution that were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for the EPA. For 2002, CH2M HILL used 36-kilomters MM5 data obtained from Alpine Geophysics, originally developed for the WRAP. Data for 2003 (also from Alpine Geophysics), at 36-kilometers resolution, were developed by the Wisconsin Department of Natural Resources, the Illinois Environmental Protection Agency, and the Lake Michigan Air Directors Consortium (Midwest RPO).

The MM5 data were used as input to CALMET as the "initial guess" wind field. The initial guess field was adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, and then further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001 through 2003 were obtained from the National Climatic Data Center. In addition, concurrent surface data collected at the Apache Generating Station were also included in developing the CALMET data. CH2M HILL processed data for all stations from the National Weather Service's (NWS) Automated Surface Observing System network that are in the domain. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website was used to convert the DATSAV3 files to CD 144 format for input to the SMERGE preprocessor and CALMET.

Land use and terrain data were obtained from the U.S. Geological Survey (USGS). Land use data were obtained in Composite Theme Grid format from the USGS, and the Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties, such as albedo, Bowen ratio, roughness length, and leaf area index, were computed from the land use values. Terrain data were taken from USGS 1 degree Digital Elevation Model data, which are primarily derived from USGS 1:250,000 scale topographic maps. Missing land use data were filled with a value that is appropriate for the missing area.

Precipitation data were ordered from the National Climate Data Center. All available data in fixed-length, TD-3240 format were ordered for the modeling domain. The list of available stations and stations that have collected complete data varies by year, but CH2M HILL processed all available stations/data within the domain for each year. Precipitation data were prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Following the methodology recommended in WRAP (2006), no observed upper-air meteorological observations were used as they are redundant to the MM5 data and may introduce spurious artifacts in the wind fields. In the development of the MM5 data, the twice-daily upper-air meteorological observations were used as input with the MM5 model. The MM5 estimates were nudged to the upper-air observations as part of the Four Dimensional Data Assimilation. This results in higher temporal (hourly versus 12-hour) and spatial (36 kilometers versus ~300 kilometers) resolution for the upper-air meteorology in the MM5 field. These MM5 data are more dynamically balanced than those contained in the upper-air observations. Therefore, the use of the upper-air observations with CALMET is not needed, and in fact, will upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities.

4.3.3 Validation of CALMET Wind Field

CH2M HILL used the CALDESK (program to display data and results) data display and analysis system (v2.97, Enviromodeling Ltda.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. CH2M HILL observed weather conditions, as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/ rescue/ dwm/ data_rescue_daily_weather_maps.html), to compare to the CALDESK displays.

4.4 CALPUFF Methodology

4.4.1 CALPUFF Modeling

CH2M HILL ran the CALPUFF model with the meteorological output from CALMET over the CALPUFF modeling domain (Figure 4-1). The CALPUFF model was used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios.

Background Ozone and Ammonia

Hourly values of background ozone concentrations were used by CALPUFF for the calculation of SO_2 and NO_x transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL used the hourly ozone data generated for the WRAP BART analysis for 2001, 2002, and 2003.

For periods of missing hourly ozone data, the chemical transformation relied on a monthly default value of 80 parts per billion. Background ammonia was set to 1 part per billion as recommended in WRAP (2006).

Stack Parameters

The baseline stack parameters for the baseline and post-control scenarios were supplied by AEPCO staff. The parameters used in the WRAP analysis appeared to be related to natural gas combustion so it was necessary to replace these with more applicable values. The same stack data were used for all scenarios since none of the emission controls related to these scenarios would significantly affect the exhaust exit flows or temperatures.

Pre-Control Emission Rates

Pre-control emission rates reflect normal maximum capacity 24-hour emissions that may occur under the source's current permit. The emission rates reflect actual emissions under normal operating conditions. As described by the EPA in the Regional Haze Regulations and Guidelines for BART Determinations; Final Rule (40 CFR Part 51; July 6, 2005, pg 39129):

> *"The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high-capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used."*

CH2M HILL used available CEM data to determine the baseline emission rates. Data reflect operations from 2001 through 2006.

Emissions were modeled for the following species:

- Sulfur dioxide (SO_2)
- Oxides of nitrogen (NO_x)
- Coarse particulate (diameter greater than $PM_{2.5}$ and less than or equal to PM_{10})
- Fine particulate (diameter less than or equal to $PM_{2.5}$)
- Elemental carbon (EC)
- Organic aerosols (SOA)
- Sulfates (SO_4)

Post-control Emission Rates

Post-control emission rates reflected the effects of the emissions control scenario under consideration. Modeled pollutants were the same as listed for the pre-control scenario.

Modeling Process

The CALPUFF modeling for the control technology options followed this sequence:

- Model WRAP-RMC parameters to verify results
- Model pre-control (baseline) emissions
- Determine the degree of visibility improvement
- Model other control scenarios if applicable
- Determine the degree of visibility improvement
- Factor visibility results into BART five-step evaluation

4.4.2 Receptor Grids and Coordinate Conversion

The TRC COORDS program was used to convert the latitude/longitude coordinates to LCC coordinates for the meteorological stations and source locations. The USGS conversion program PROJ (version 4.4.6) was used to convert the National Park Service receptor location data from latitude/longitude to LCC map.

For the Class I areas that are within 300 kilometers of the Apache Power Plant, discrete receptors for the CALPUFF modeling were taken from the National Park Service database for Class I area modeling receptors. The entire area of each Class I area that is within or intersects the 300-kilometer circle (Figure 4-1) were included in the modeling analysis. The following lists the Class I areas that were modeled for the Apache facility:

- Chiricahua Wilderness and National Monument (NM)
- Galiuro WA
- Gila WA
- Mazatzal WA
- Mount Baldy WA
- Pine Mountain WA

- Saguaro NP
- Sierra Ancha WA
- Superstition WA

4.5 Visibility Post-processing

4.5.1 CALPOST

The CALPOST processor was used to determine 24-hour average visibility results. Output is specified in deciview (dV) units.

Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values was used to calculate the delta-dV (Δdv) change relative to natural background. The following default extinction coefficients for each species, as shown below, were used:

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST Visibility Method 6 (MVISBK=6) was used for the determination of visibility impacts. Monthly average relative humidity factors (*f*[RH]) were used in the light extinction calculations to account for the hygroscopic characteristic of sulfate and nitrate particles. Monthly *f*(RH) values, from the WRAP_RMC BART modeling, were used in CALPOST for the particular Class I area being modeled.

The natural background conditions used in the post-processing to determine the change in visual range background—or ΔdV—represent the average natural background concentration for western Class I areas.

Table 4-2 lists the annual average species concentrations from the EPA Guidance.

TABLE 4-2
AVERAGE NATURAL LEVELS OF AEROSOL COMPONENTS

Aerosol Component	Average Natural Concentration ($\mu h/m^3$) for Western Class I Areas
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

NOTE:
Taken from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule. EPA-454/B-03-005, September 2003.

4.6 Results

Input and output files for the CALMET/CALPUFF modeling and post-processing will be provided in electronic format to Arizona Department of Environmental Quality (ADEQ). Larger files, such as binary files generated by CALMET, have not been included on the submitted disks, but any omitted files will be provided electronically upon request.

4.6.1 WRAP Verification Runs Results

Tables 4-3 and 4-4 present the results of WRAP-RMC model verification runs. The results show good correlation in estimated maximum ΔdV. Much of the difference between these values is probably attributed to the different alignment of the LCC map grids.

TABLE 4-3
RESULTS FROM WRAP-RMC CALPUFF MODELING FOR ST1-3 (WRAP 2007)

Class I Area	Min Distance (kilometers)	Max Delta ΔdV	98th Percentile ΔdV	Days > 0.5 ΔdV	98th Percentile ΔdV for Each Year			98th ΔdV 3-year Avg
					2001	2002	2003	
Chiricahua	45	3.56	1.96	291	1.93	1.86	2.07	1.95
Galiuro	53	3.06	1.35	141	1.35	1.16	1.67	1.39
Saguaro	57	2.25	1.37	152	1.44	1.25	1.31	1.33
Gila	167	1.00	0.60	31	0.62	0.73	0.47	0.61
Superstition	183	2.66	0.61	41	0.55	0.61	0.76	0.64
Mt. Baldy	207	1.27	0.29	9	0.26	0.34	0.29	0.30
Sierra Ancha	208	2.05	0.43	17	0.42	0.43	0.41	0.42
Mazatzal	254	2.07	0.44	16	0.45	0.44	0.36	0.42
Pine Mt.	300	1.74	0.34	14	0.44	0.34	0.27	0.35

TABLE 4-4
VERIFICATION CALPUFF MODELING RESULTS

Class I Area	Min Distance (kilometers)	Max Delta ΔdV	98th Percentile ΔdV	Days > 0.5 ΔdV	98th Percentile ΔdV for each year			98th ΔdV 3-year Avg
					2001	2002	2003	
Chiricahua	46	4.326	2.758	173	2.806	2.890	2.614	2.770
Galiuro	54	4.899	2.062	78	2.215	1.895	2.291	2.134
Saguaro	58	3.839	2.282	102	2.521	1.935	2.332	2.263
Gila	167	1.606	0.709	24	0.709	0.757	0.686	0.717
Superstition	183	3.166	0.995	33	1.006	0.861	1.092	0.986
Mt. Baldy	208	1.248	0.417	6	0.352	0.476	0.357	0.395
Sierra Ancha	208	2.434	0.649	15	0.647	0.750	0.596	0.664
Mazatzal	255	2.516	0.605	11	0.634	0.574	0.491	0.566
Pine Mt.	301	2.065	0.483	8	0.536	0.558	0.362	0.485

4.6.2 BART Least Cost Analysis

The results and comparisons of the CALPUFF modeling for the baseline emission rates and those for the alternative emission control scenarios are provided in Section 5.

Section 5.0
Preliminary Assessment
and Recommendations

5.0 Preliminary Assessment and Recommendations

5.1 Preliminary Recommended BART Controls

As a result of the completed technical and economic evaluations, and consideration of the modeling analysis for ST1, the preliminary recommended BART controls for NO_x, SO_2, and PM_{10} are as follows:

- The most cost-effective emissions control scenario includes using PNG as fuel and the installation of LNB and FGR.
- LNB and FGR for NO_x control.

The above NO_x recommendations were identified as Scenario 1 for the modeling analysis described in Section 4.0. Visibility improvements for all emission control scenarios were analyzed, and the results are compared below, using a least-cost envelope, as outlined in the draft EPA *New Source Review Workshop Manual* (1990).

5.2 Analysis Baseline and Scenarios

Table 5-1 compares the six emission control scenarios with expected emission levels. These scenarios have been developed to examine the effects of NO_x controls and PM_{10}/SO_2 controls independently. For the NO_x scenarios (Scenarios 1 through 5), PM_{10} and SO_2 are modeled at the baseline levels. For the PM_{10}/SO_2 scenarios (Scenarios 6 and 7), NO_x is modeled at the baseline level. Although these scenarios may not reflect the potential improvements from emission controls for all pollutants, these allow independent assessment of controls for each pollutant.

Emission control scenarios for PM_{10} and SO_2 have combined into a single analysis to create sufficient data points for these analyses.

All these scenarios assume combustion of No. 6 fuel oil. In general, this fuel represents the worst-case emissions for all pollutants and emission control scenarios.

TABLE 5-1
EMISSION CONTROL SCENARIOS
ST1

Case	Description	Expected NO_x Emissions (lb/MMBtu)	Expected SO_2 Emissions (lb/MMBtu)	Expected PM_{10} Emissions (lb/MMBtu)
Baseline		0.301	0.906	0.074
Scenario 1	LNB with FGR	0.150	0.906	0.074
Scenario 2	ROFA	0.160	0.906	0.074
Scenario 3	ROFA with Rotamix	0.110	0.906	0.074
Scenario 4	LNB with FGD and SNCR	0.110	0.906	0.074
Scenario 5	SCR	0.070	0.906	0.074
Scenario 6	Fabric Filter/SDA	0.301	0.100	0.015
Scenario 7	Fabric Filter	0.301	0.906	0.015

The ranking of the different NO_x emission control scenarios based on annual costs, from lowest to highest cost, is presented on Table 5-2. The ranking of the particulate matter control scenarios based on annual costs, from lowest to highest cost, is presented in Table 5-3.

TABLE 5-2
RANKING OF NO_X CONTROL SCENARIOS BY COST
ST1

Rank	Scenario	Total Annual Cost
1	Scenario 1	$551,982
2	Scenario 2	$939,093
3	Scenario 4	$1,079,389
4	Scenario 3	$1,505,825
5	Scenario 5	$5,704,798

TABLE 5-3
RANKING OF PARTICULATE MATTER AND SO_2 CONTROL SCENARIOS BY COST
ST1

Rank	Scenario	Total Annual Cost
1	Scenario 7	$3,615,938
2	Scenario 6	$7,497,644

The Baseline of this BART analysis was defined as the level of NO_x, SO_2, and PM_{10} emission control that would be representative of future operations without the additional cost and level of control associated with the scenarios. Figures 5-1 through 5-4 compare the modeled contribution to visual range reduction for each Class I area for the baseline and each NO_x emission control scenario. Figures 5-5 through 5-8 compare the modeled contribution to visual range reduction for each Class I area for the baseline and each particulate matter/SO_2 emission control scenario.

Of the nine Class I areas included in this analysis, results from the analysis for four of these areas are presented in this chapter. These four areas were selected because they represented the maximum impacts shown on Tables 4-3 and 4-4. The results for all nine areas are presented in Appendix C. The four selected areas include the following:

- Chiricahua WA and NM
- Galiuro WA
- Saguaro NP
- Superstition WA

The facility impacts presented Table 4-4 demonstrates that predicted impacts at the above areas are more significant than those at the other Class I areas.

FIGURE 5-1
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Chiricahua WA and NM
ST1

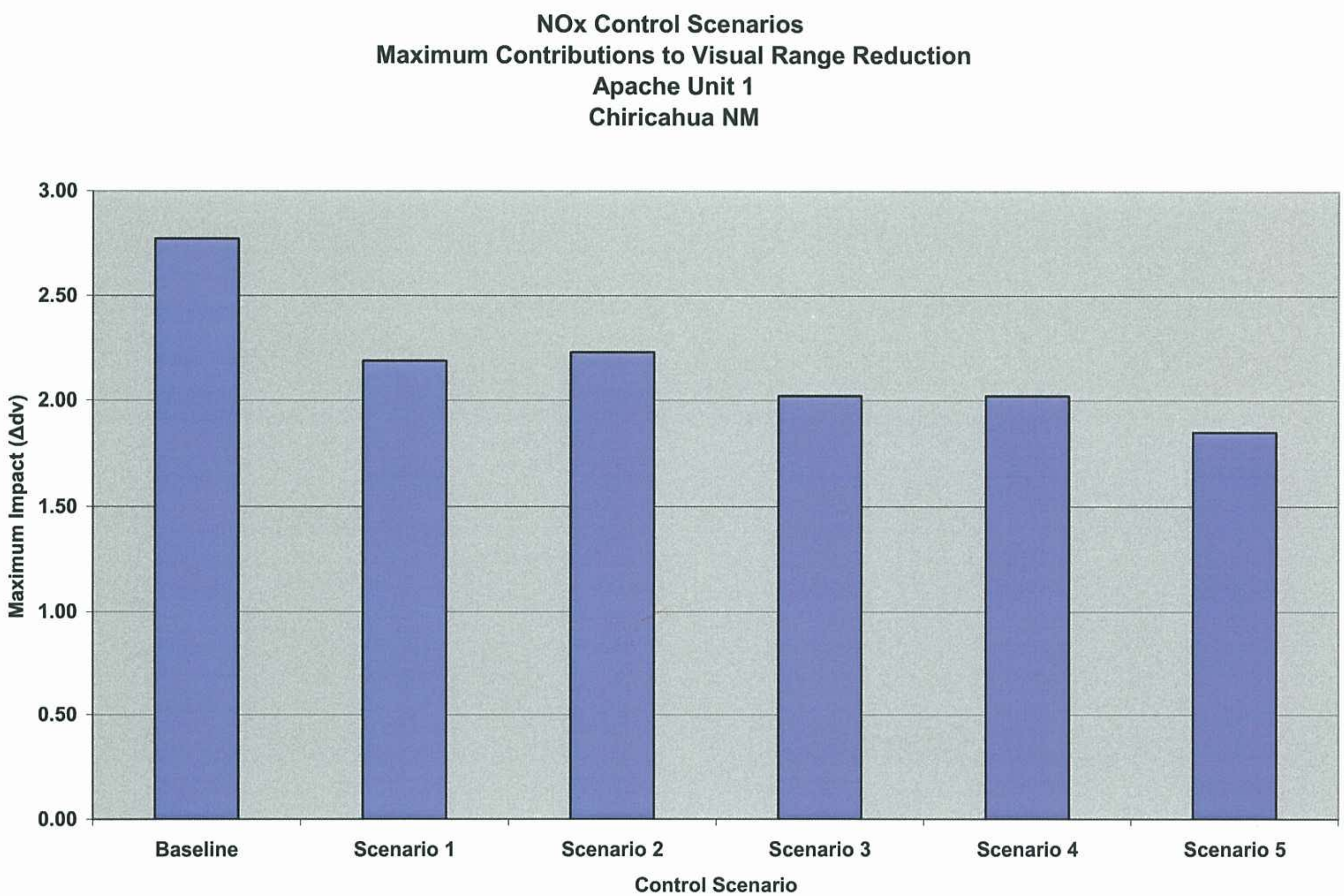


FIGURE 5-2
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Galiuro WA
ST1

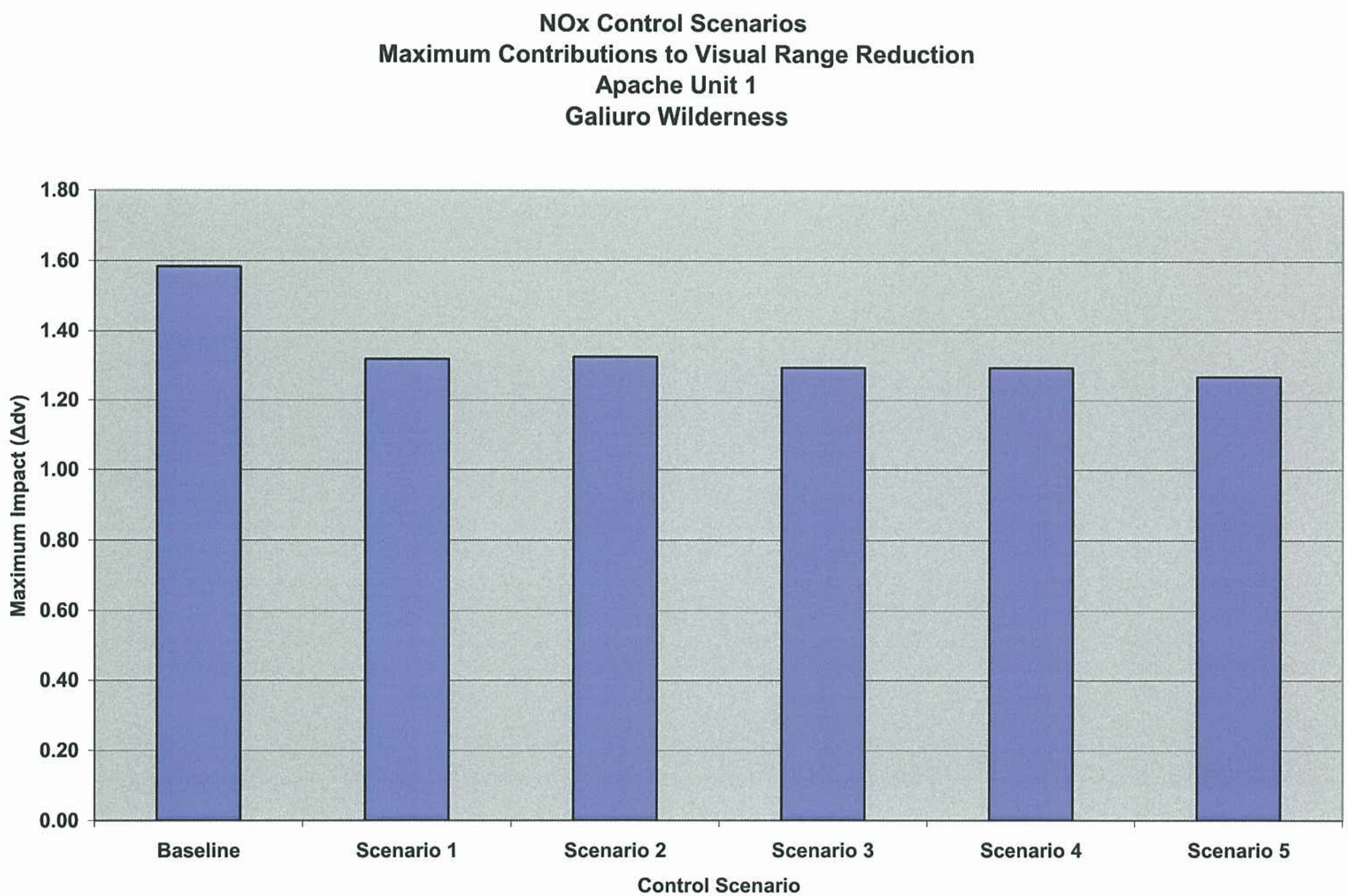


FIGURE 5-3
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Saguaro NP
ST1

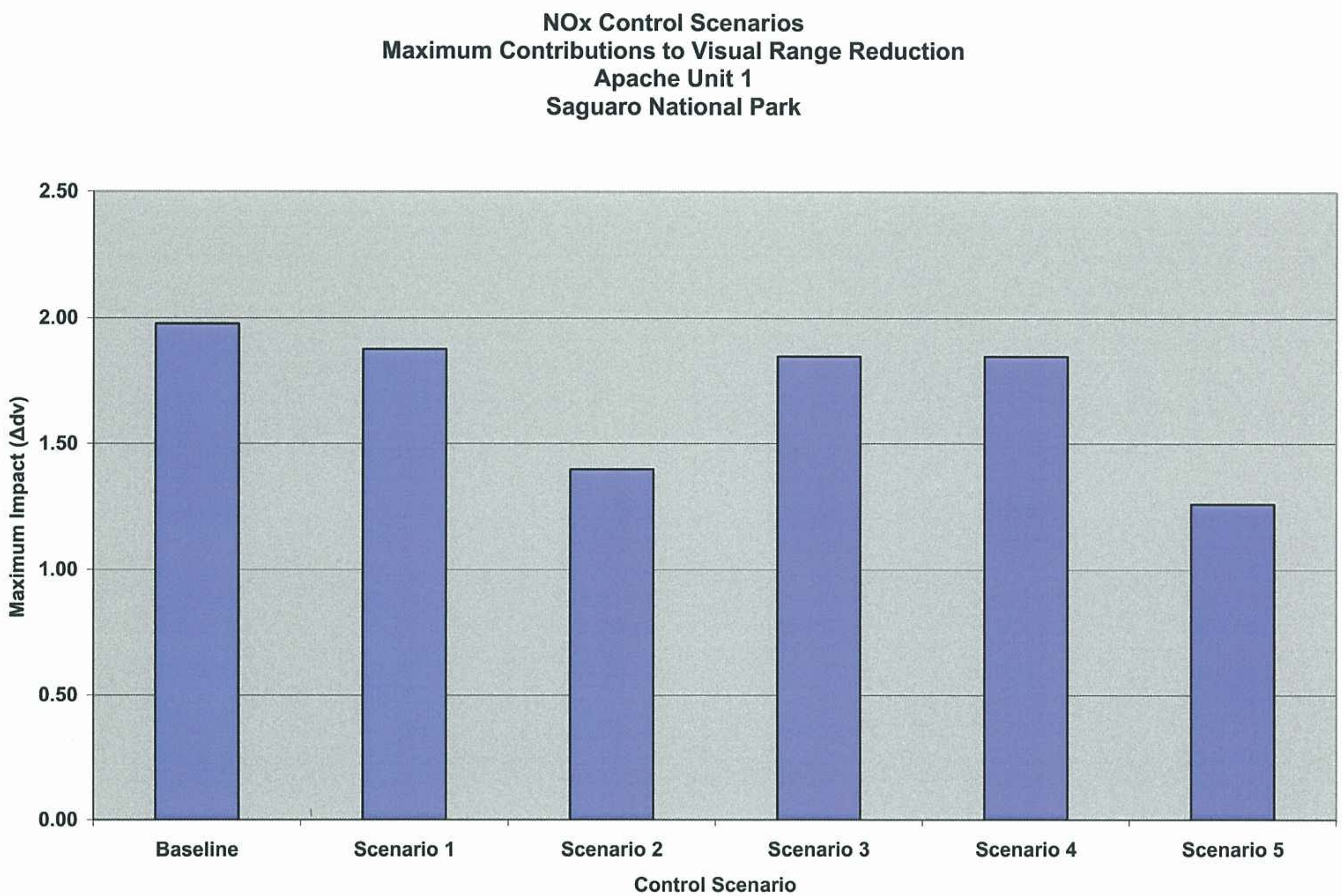


FIGURE 5-4
NO_x Control Scenarios—Maximum Contributions to Visual Range Reduction at Superstition WA
ST1

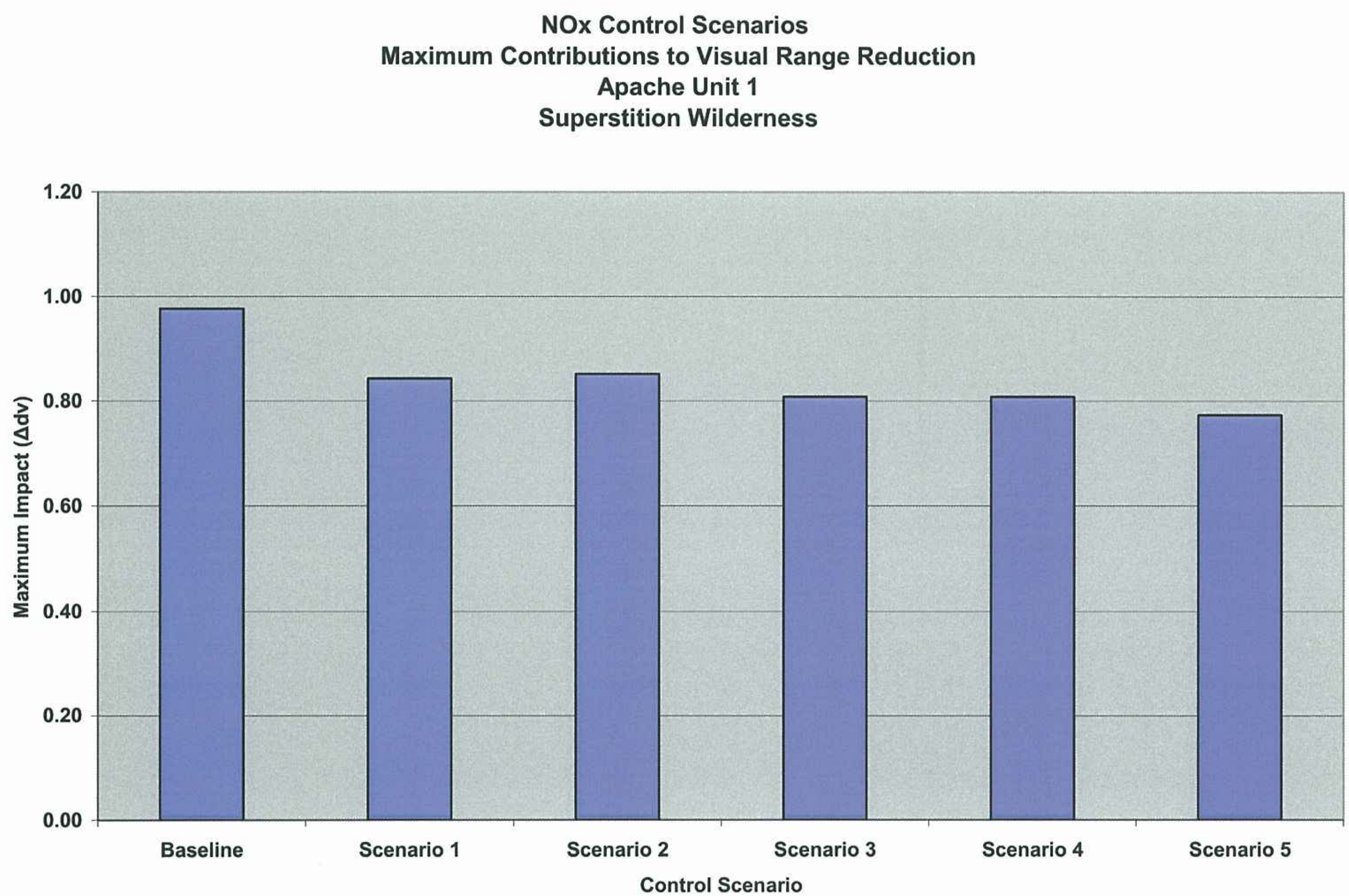


FIGURE 5-5
Particulate Matter and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Chiricahua WA and NM
ST1

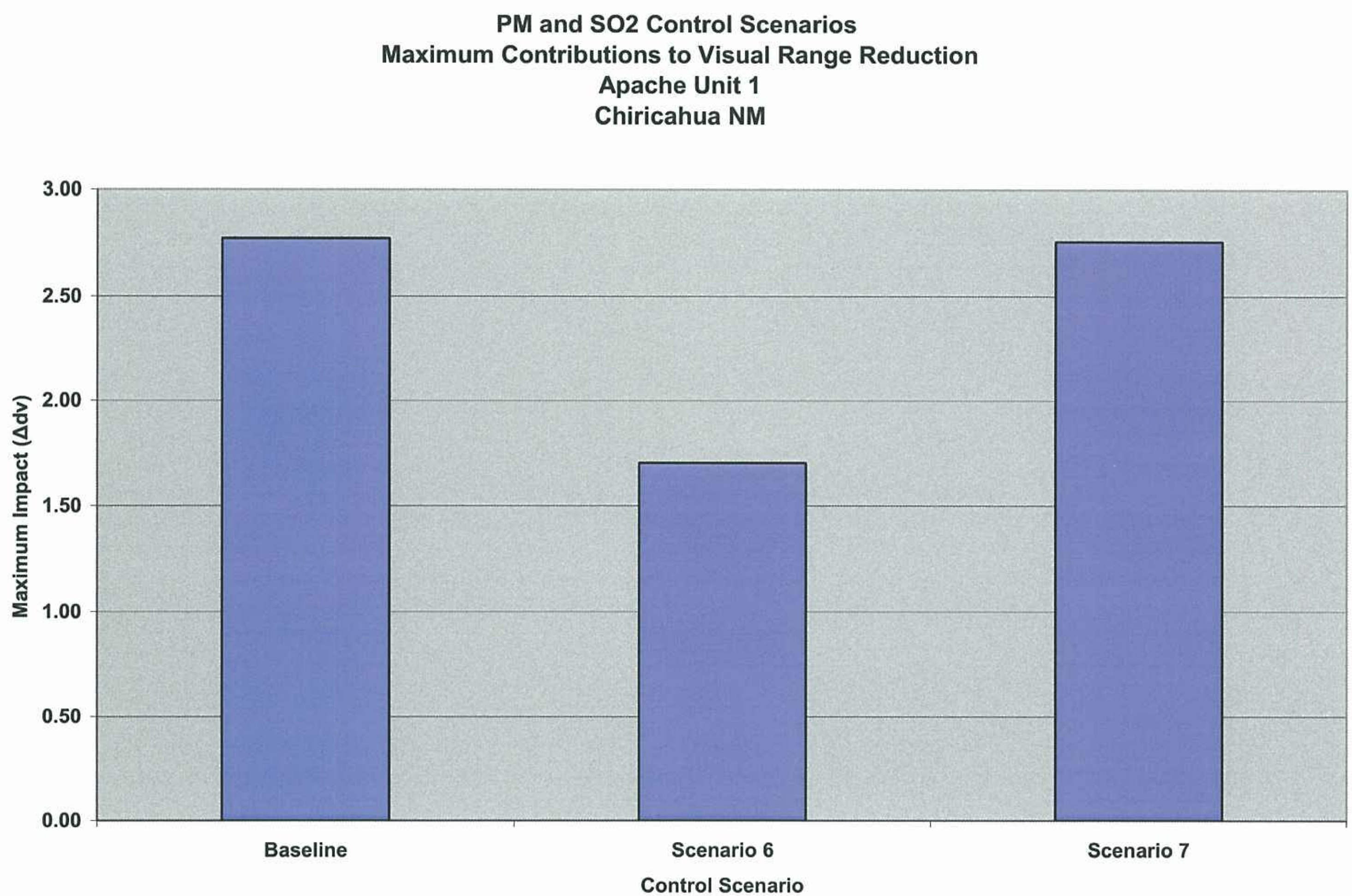


FIGURE 5-6
Particulate Matter and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Galiuro WA
ST1

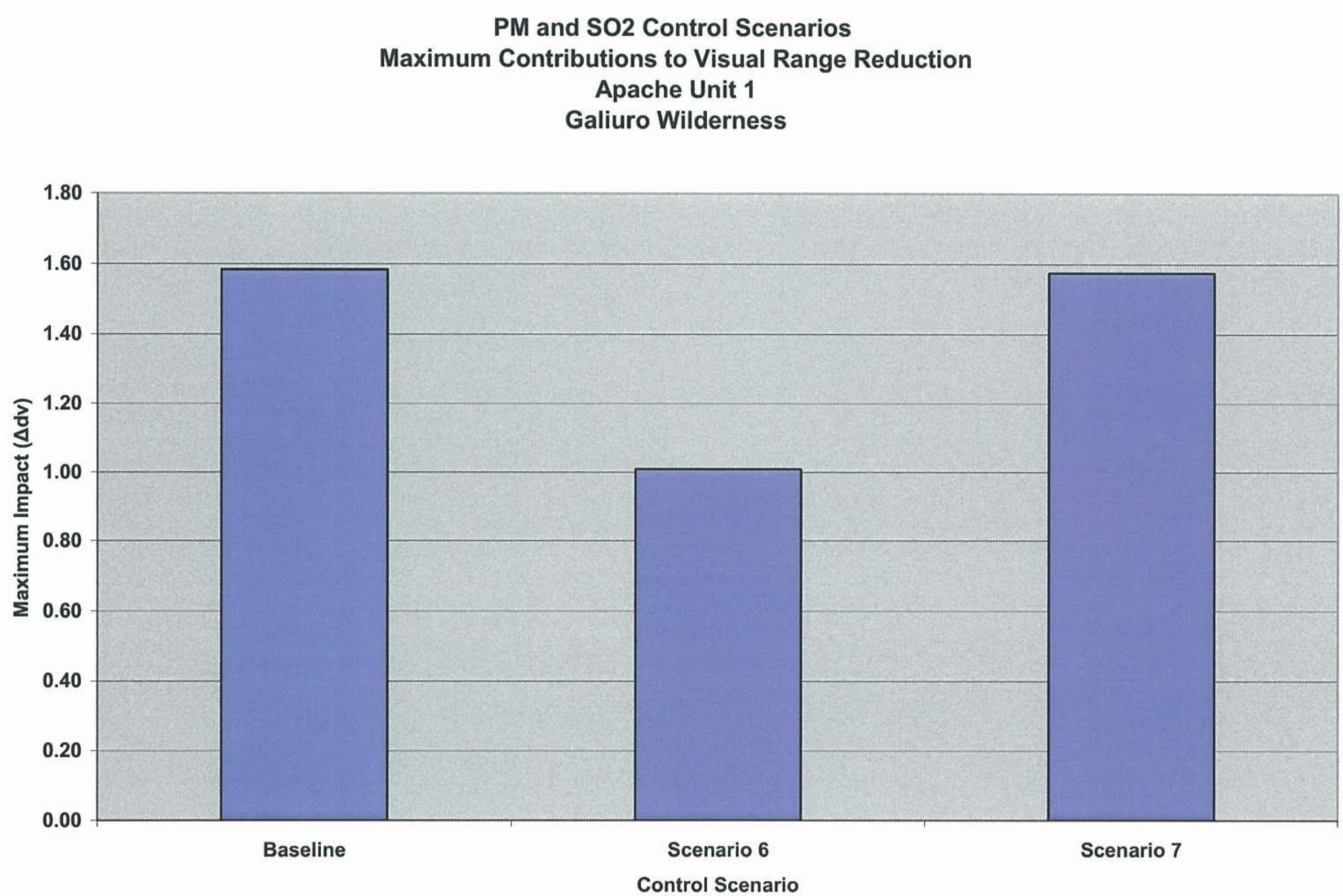


FIGURE 5-7
Particulate Matter and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Saguaro NP
ST1

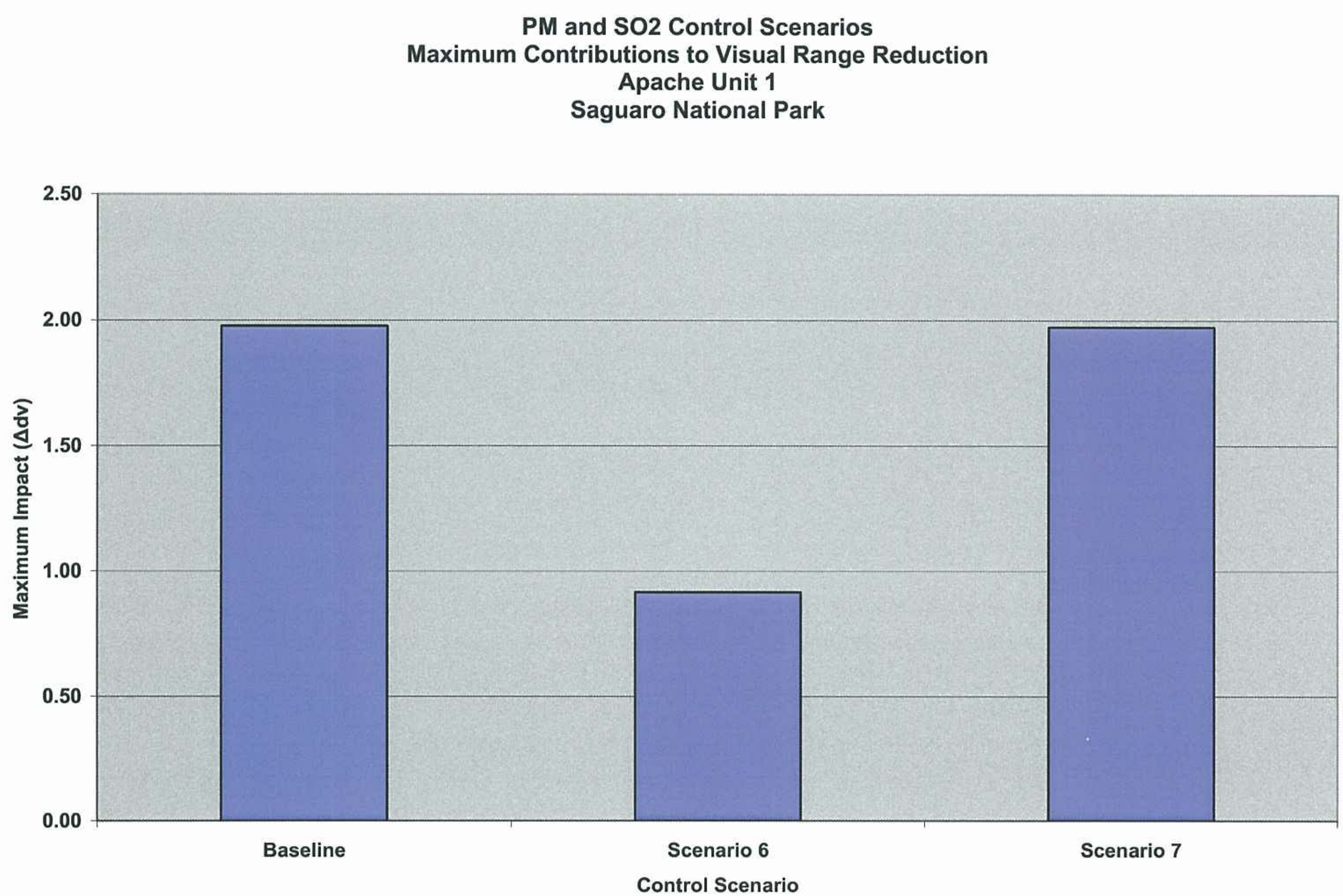
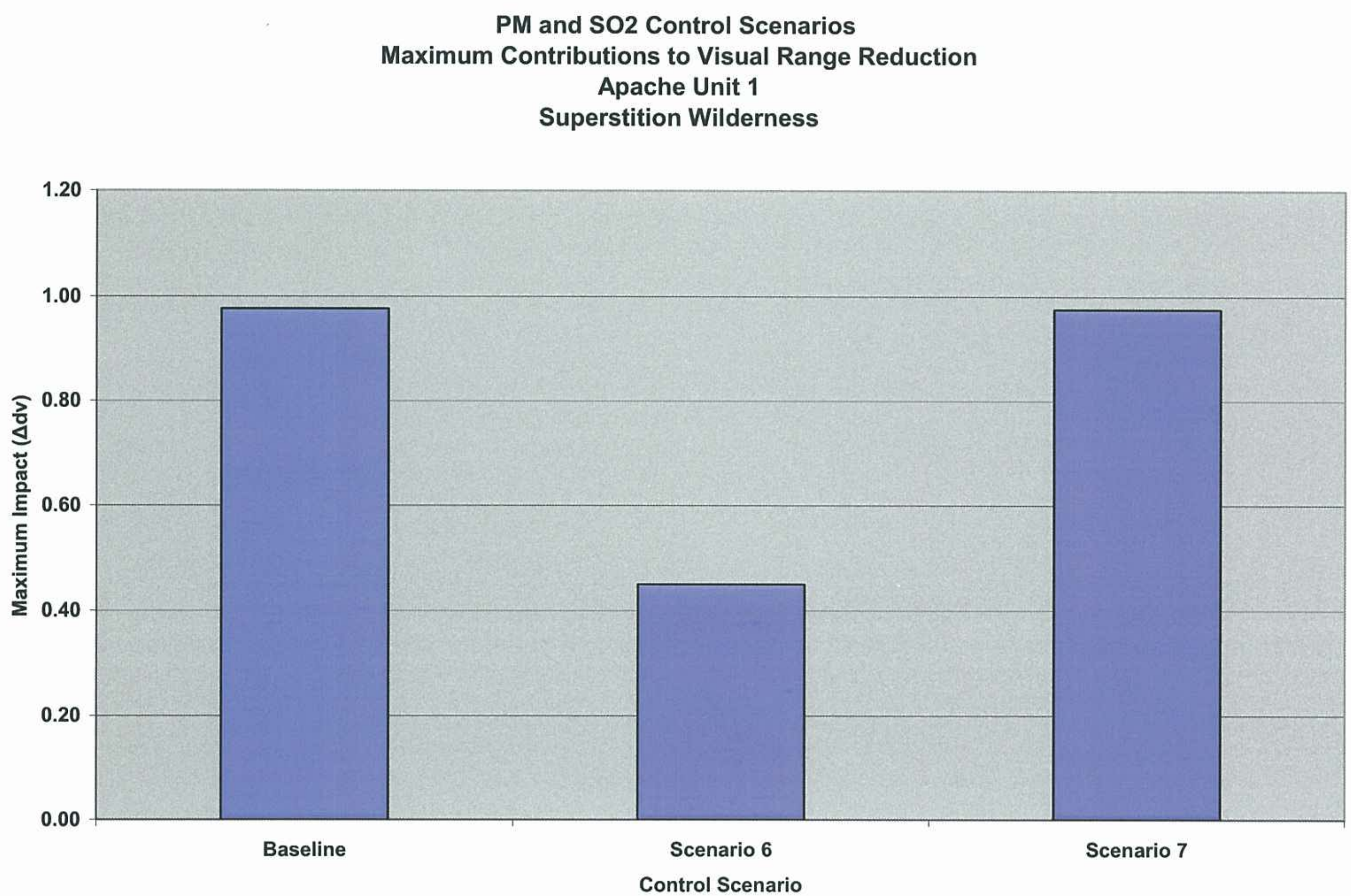


FIGURE 5-8
Particulate Matter and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Superstition Wilderness
ST1



5.3 Least-Cost Envelope Analysis

The total annualized cost, cost per ΔdV reduction, and cost per reduction in number of days above 0.5 ΔdV for each of the NO_x emission control scenarios and each of the selected Class I areas are listed in Tables 5-4 through 5-7. A comparison of the incremental costs between relevant scenarios is shown in Tables 5-8 through 5-11. The total annualized cost versus number of days above 0.5 ΔdV, and the total annualized cost versus 98th percentile ΔdV reduction are shown in Figures 5-9 through 5-16 for the nine Class I areas.

5.3.1 Analysis Methodology

On page B-41 of the *New Source Review Workshop Manual* (EPA, 1990), the EPA states that,

> *"Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis..."*

An analysis of incremental cost effectiveness has been conducted. This analysis was performed in the following way. Control scenarios are selected from points that fall on the least-cost envelope curves (Figures 5-9 through 5-16). The incremental cost-effectiveness data, expressed per day and per ΔdV, represents a comparison of the different scenarios, and is summarized in Tables 5-8 through 5-11 for each of the Class I areas. Then the most reasonable smooth curve of least-cost control option scenarios is plotted for each analysis. Figures 5-9 through 5-16 present the cost per ΔdV reduction for the Class I areas.

TABLE 5-4
NOx CONTROL SCENARIO RESULTS FOR CHIRICAHUA WA AND NM
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/ Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		88	0.000	0.000	0.000	0.000
1	LNB with FGR	77	0.194	0.552	0.050	2.845
2	ROFA	77	0.256	0.939	0.085	3.668
3	ROFA with Rotamix	73	0.240	1.506	0.100	6.274
4	LNB with FGD and SNCR	73	0.240	1.079	0.072	4.497
5	SCR	71	0.409	5.705	0.336	13.948

TABLE 5-5
NOx CONTROL SCENARIO RESULTS FOR GALIURO WA
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)

TABLE 5-5
NO_X CONTROL SCENARIO RESULTS FOR GALIURO WA
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98^{th} Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		28	0.000	0.000	0.000	0.000
1	LNB with FGR	25	0.084	0.552	0.184	6.571
2	ROFA	16	0.148	0.939	0.078	6.345
3	ROFA with Rotamix	25	0.102	1.506	0.502	14.763
4	LNB, FGD and SNCR	25	0.102	1.079	0.360	10.582
5	SCR	13	0.203	5.705	0.380	28.102

TABLE 5-6
NO_X CONTROL SCENARIO RESULTS FOR SAGUARO NATIONAL PARK
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98^{th} Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		35	0.000	0.000	0.000	0.000
1	LNB with FGR	29	0.117	0.552	0.092	4.718
2	ROFA	29	0.222	0.939	0.157	4.230
3	ROFA with Rotamix	29	0.152	1.506	0.251	9.907
4	LNB, FGD and SNCR	29	0.152	1.079	0.180	7.101
5	SCR	23	0.294	5.705	0.475	19.404

TABLE 5-7
NO_X CONTROL SCENARIO RESULTS FOR SUPERSTITION WA
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		4	0.000	0.000	0.000	0.000
1	LNB with FGR	4	0.026	0.552	NA	21.230
2	ROFA	4	0.047	0.939	NA	19.981
3	ROFA with Rotamix	4	0.030	1.506	NA	50.194
4	LNB with FGD and SNCR	4	0.030	1.079	NA	35.980
5	SCR	4	0.060	5.705	NA	95.080

TABLE 5-8
CHIRICAHUA WA AND NM NO_X CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	11	0.194	0.552	0.050	2.845
Scenario 2 vs. Scenario 1	0	0.062	0.387	NA	6.244
Scenario 5 vs. Scenario 2	6	0.153	4.766	0.794	31.148

TABLE 5-9
GALIURO WA NO_X CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	3	0.084	0.552	0.184	6.571
Scenario 2 vs. Scenario 1	9	0.064	0.387	0.043	6.049
Scenario 5 vs. Scenario 2	3	0.055	4.766	1.589	86.649

TABLE 5-10
SAGUARO NP NO_X CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	6	0.117	0.552	0.092	4.718
Scenario 2 vs. Scenario 1	0	0.105	0.387	NA	3.687
Scenario 5 vs. Scenario 2	6	0.072	4.766	0.794	66.190

TABLE 5-11
SUPERSTITION WA NO_X CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	0	0.026	0.552	NA	21.230
Scenario 2 vs. Scenario 1	0	0.021	0.387	NA	18.434
Scenario 5 vs. Scenario 2	0	0.013	4.766	NA	366.592

FIGURE 5-9
NO_x Control Scenarios—Least-Cost Envelope Chiricahua WA and NM—Days Reduction
ST1

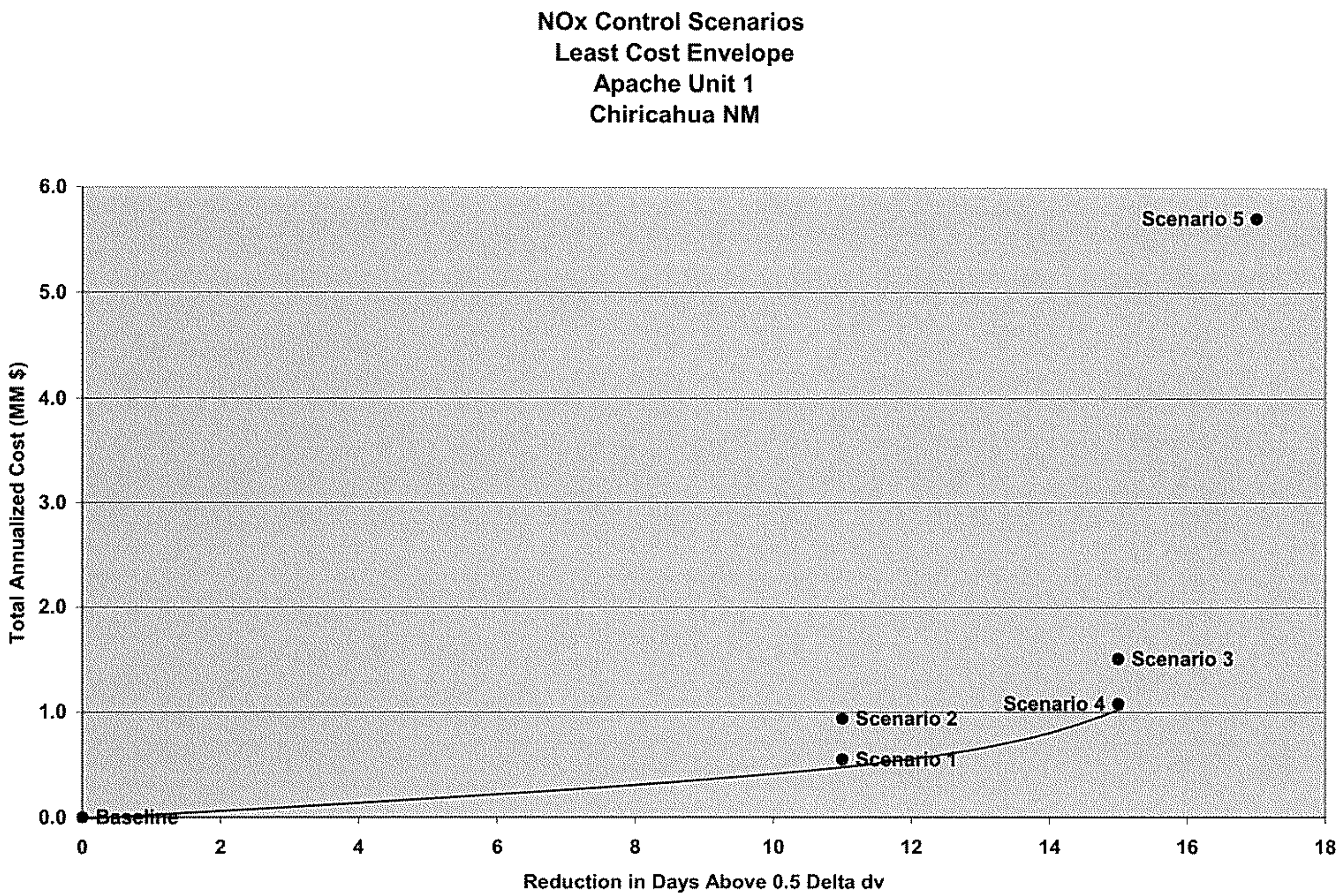


FIGURE 5-10
NO_x Control Scenarios—Least-Cost Envelope Chiricahua WA and NM—98th Percentile Reduction
ST1

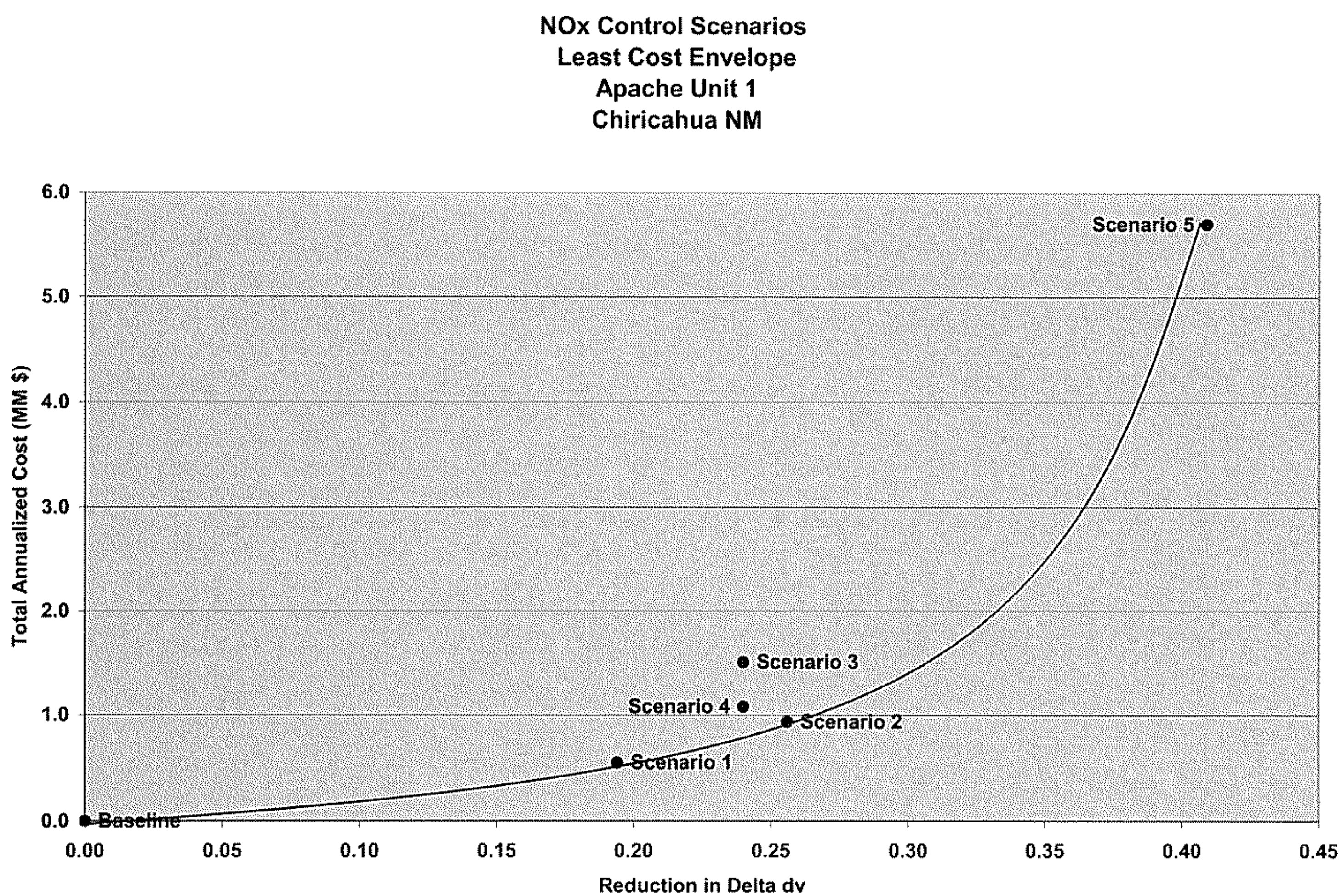


FIGURE 5-11
NO_x Control Scenarios—Least-Cost Envelope Galiuro WA—Days Reduction
ST1

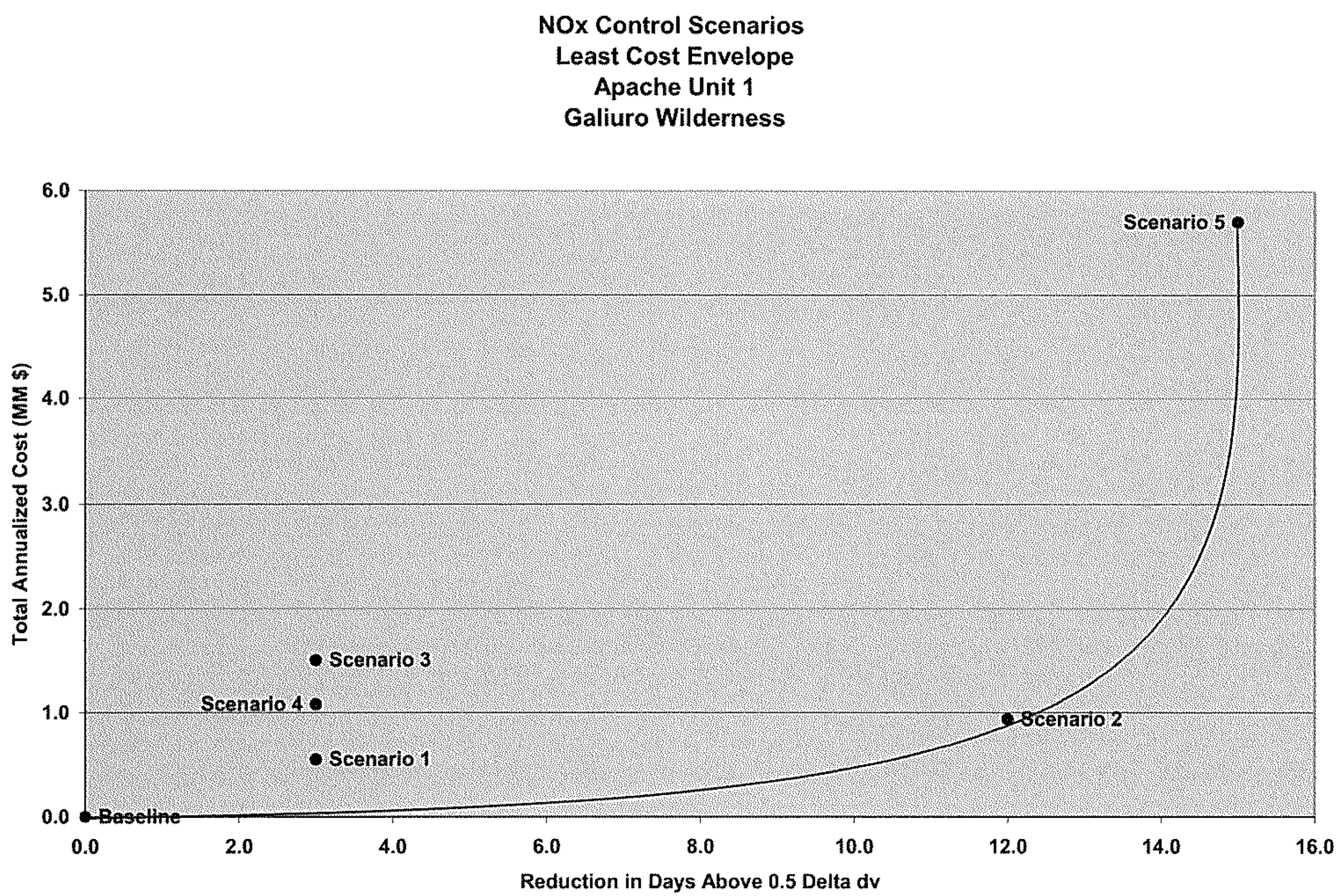


FIGURE 5-12
NO_x Control Scenarios—Least-Cost Envelope Galiuro WA—98th Percentile Reduction
ST1

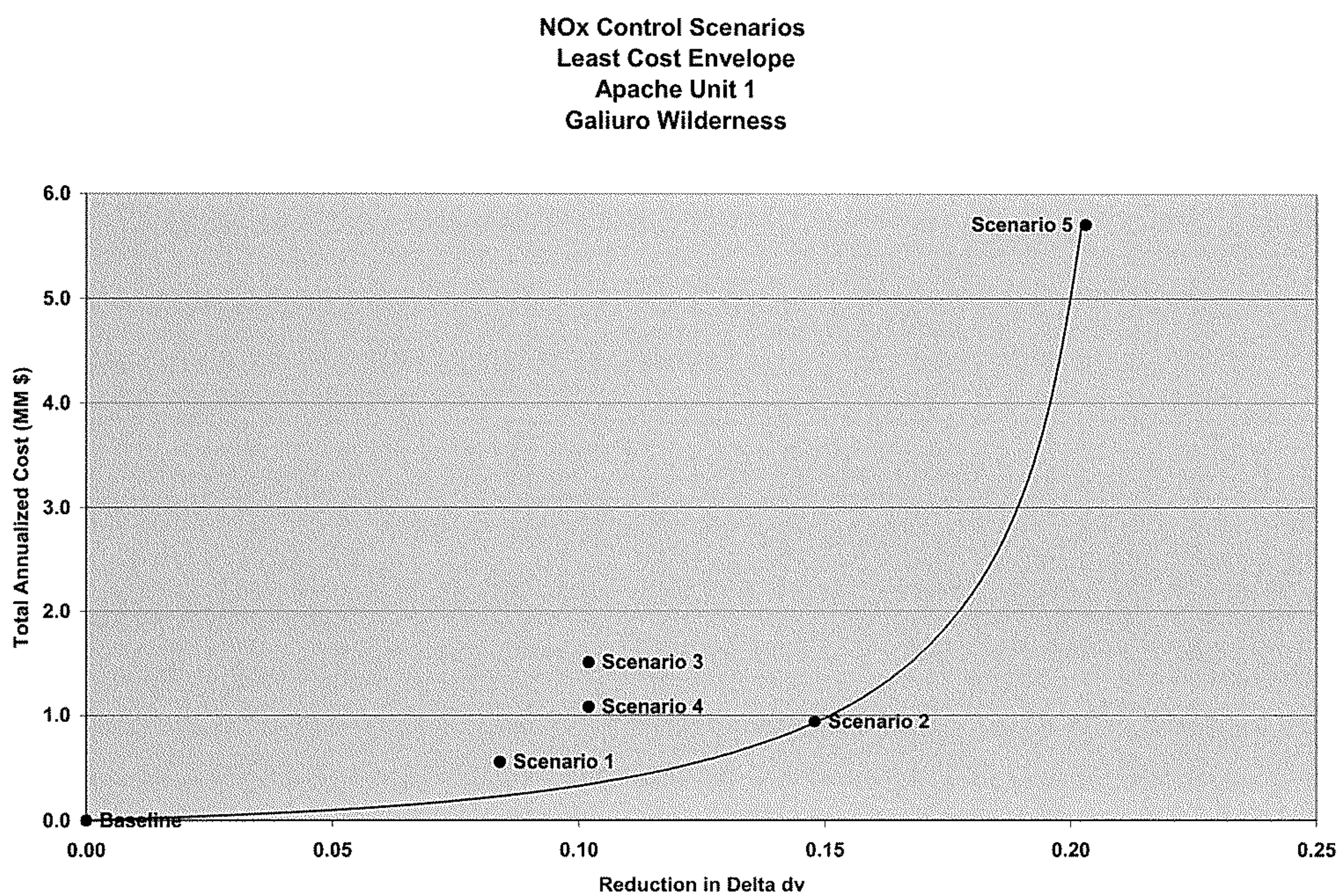


FIGURE 5-13
NO_x Control Scenarios—Least-Cost Envelope Saguaro NP—Days Reduction
ST1

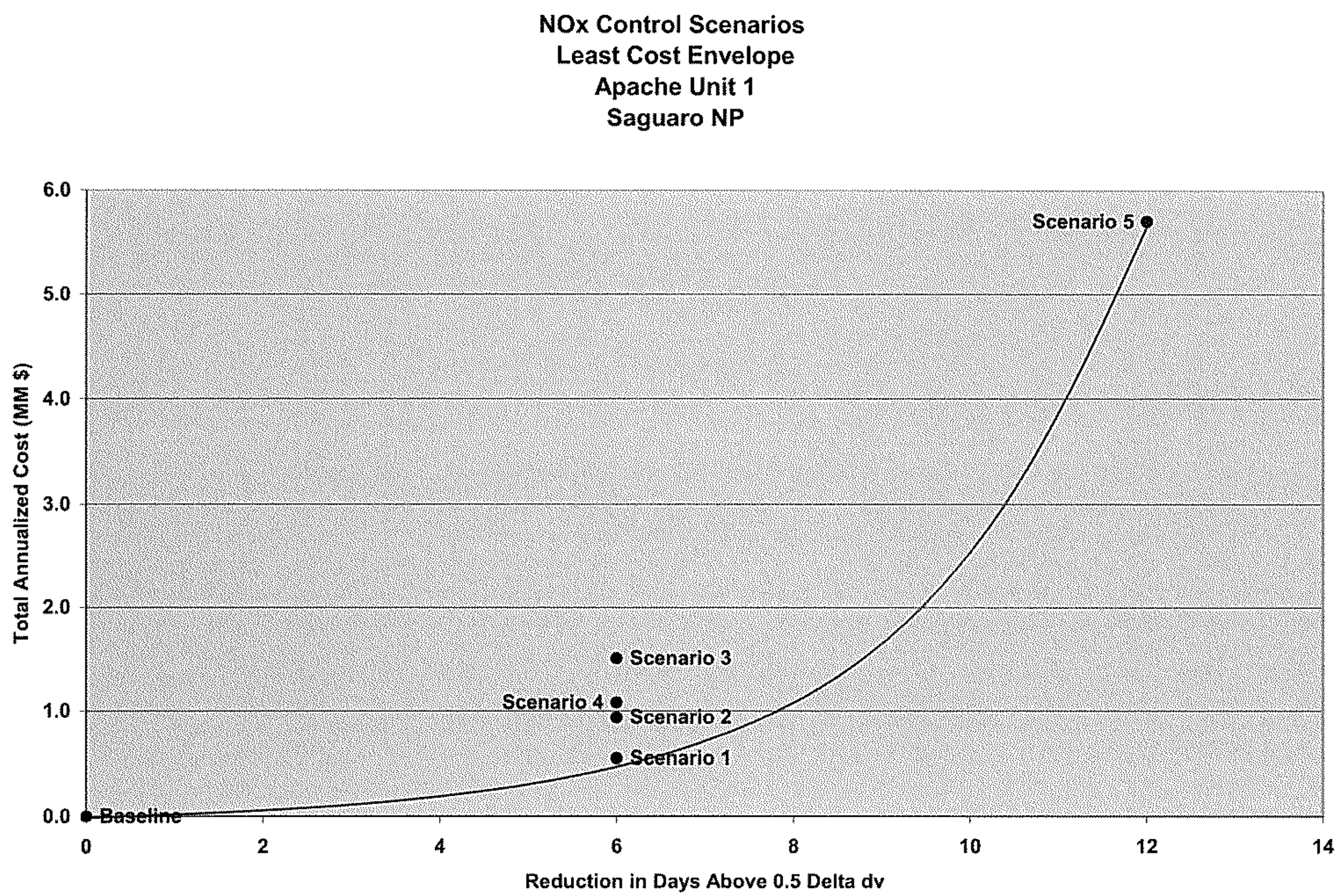


FIGURE 5-14
NO_x Control Scenarios—Least-Cost Envelope Saguaro NP—98th Percentile Reduction
ST1

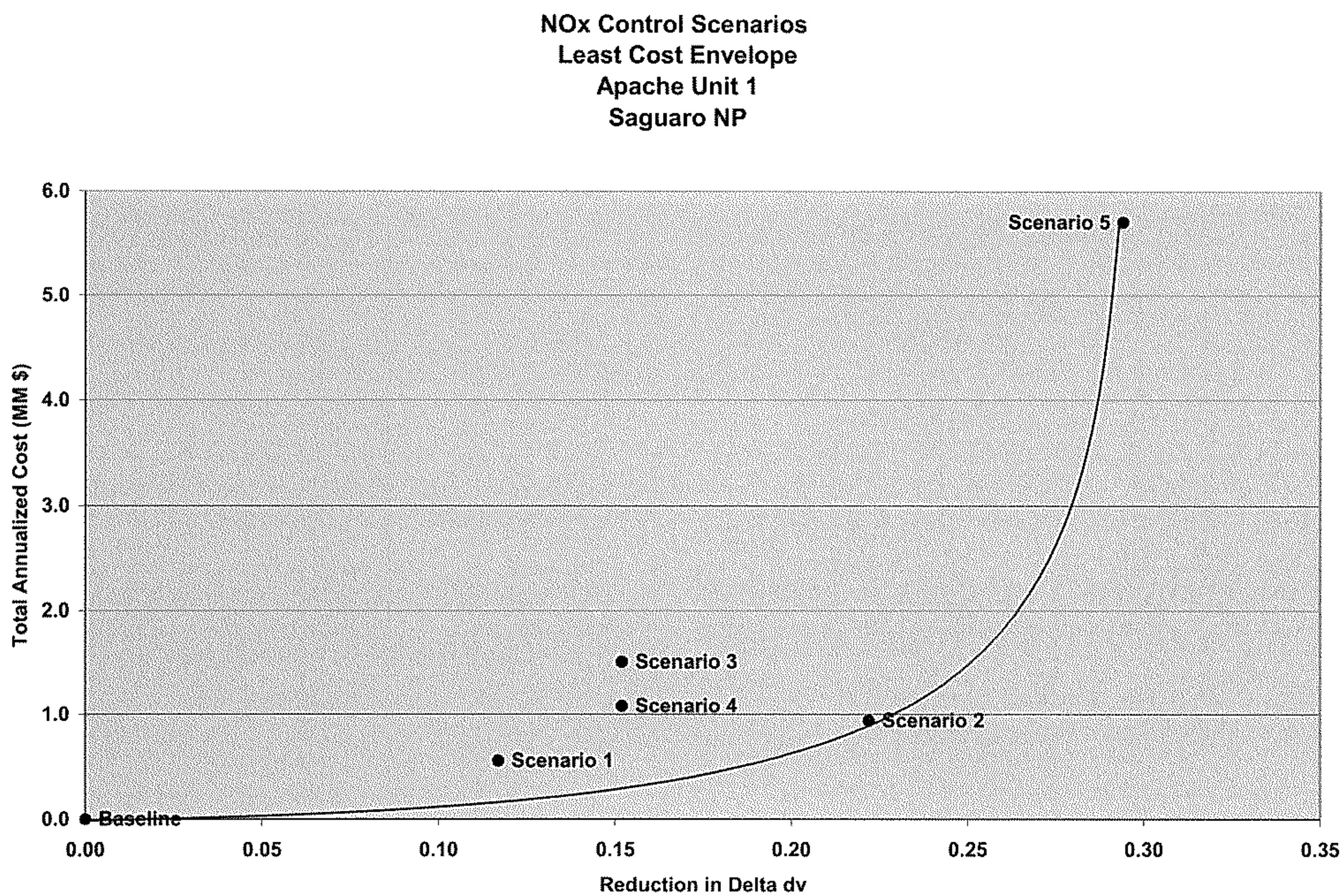


FIGURE 5-15
NO_x Control Scenarios—Least-Cost Envelope Superstition WA—Days Reduction
ST1

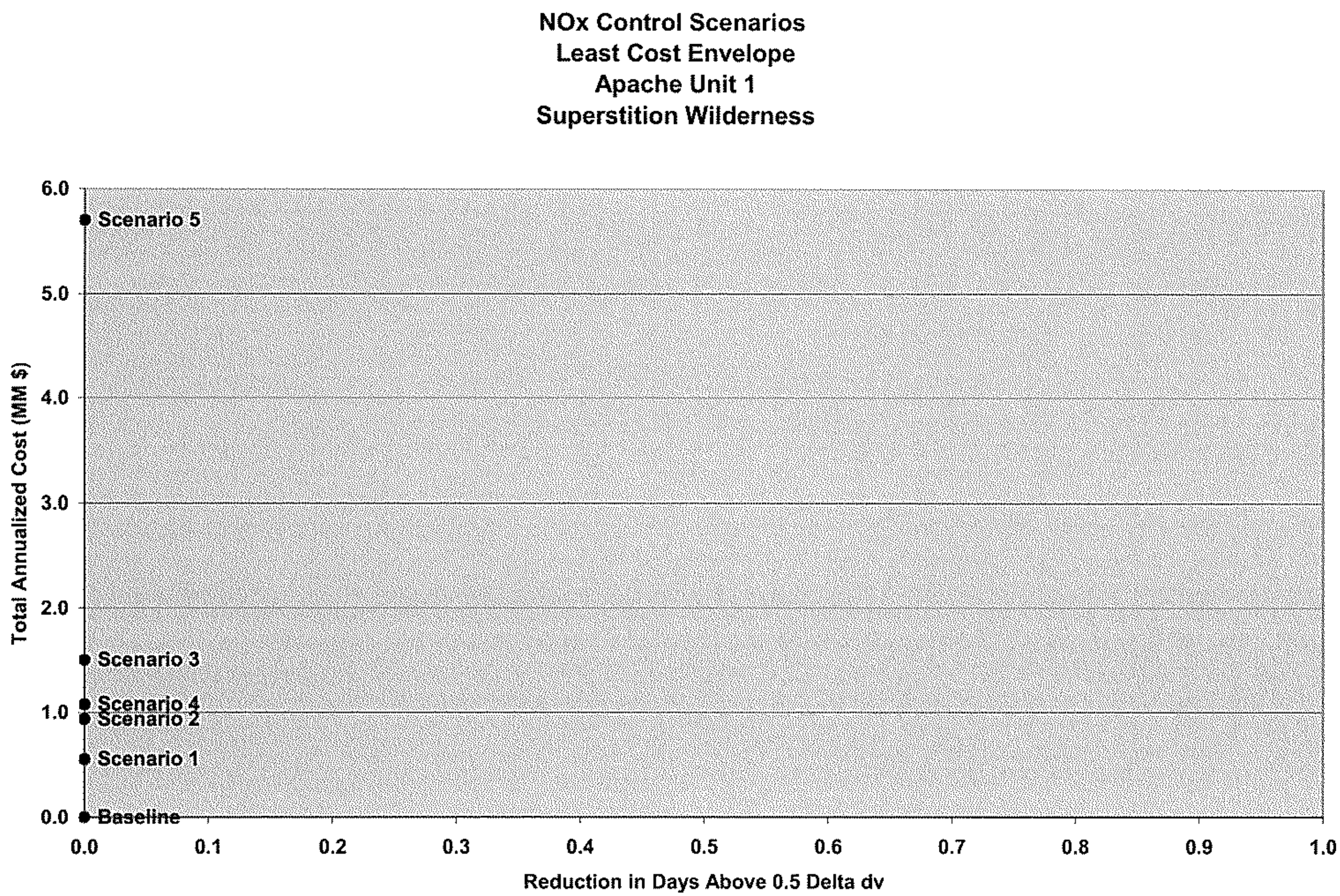


FIGURE 5-16
NO_x Control Scenarios—Least-Cost Envelope Superstition WA—98th Percentile Reduction
ST1

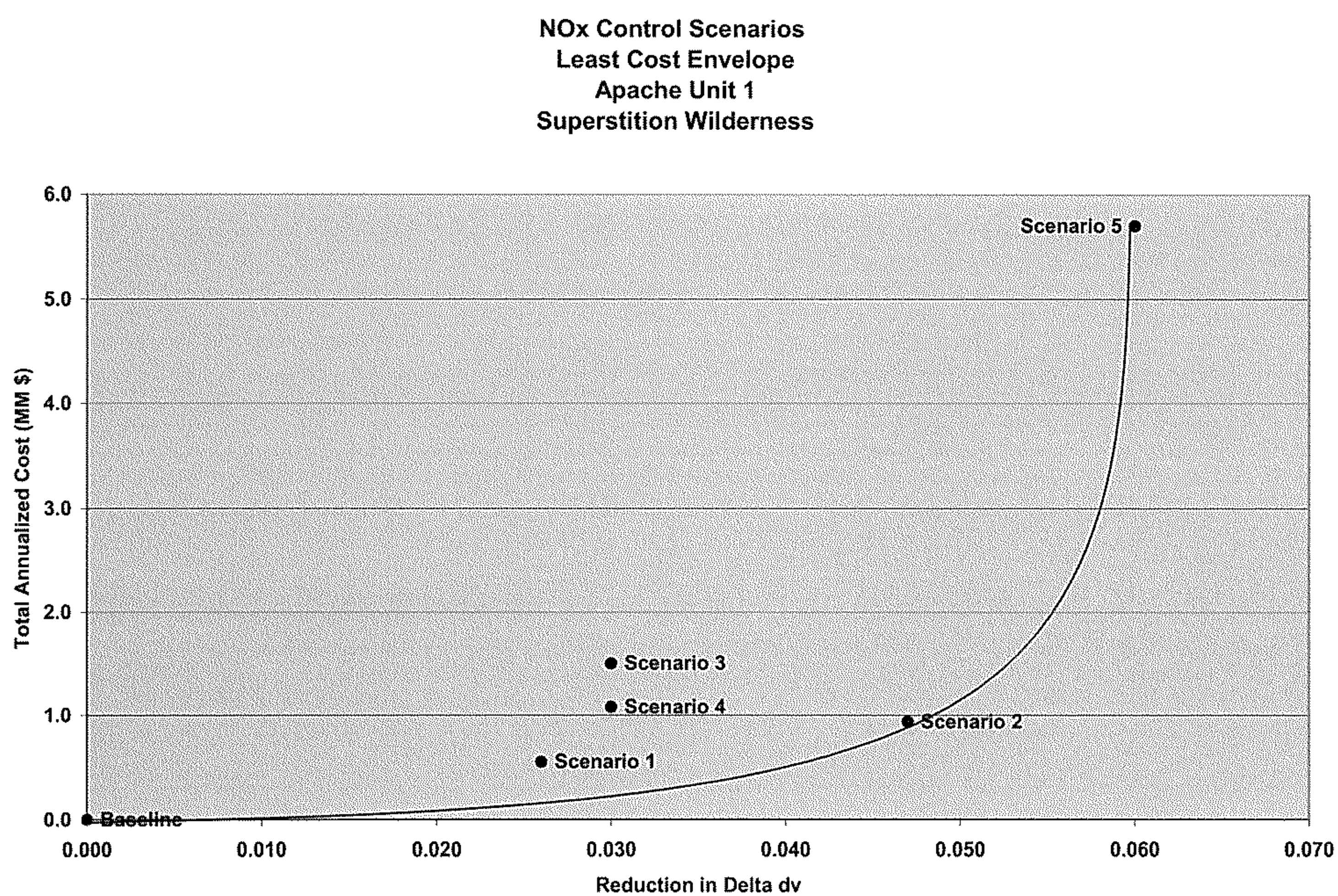


TABLE 5-12
PARTICULATE MATTER AND SO_2 CONTROL SCENARIO RESULTS FOR CHIRICAHUA WA AND NM
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		88	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	19	0.765	7.498	0.109	9.801
7	Fabric Filter	85	0.010	3.616	1.205	361.594

TABLE 5-13
PARTICULATE MATTER AND SO_2 CONTROL SCENARIO RESULTS FOR GALIURO WA
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		28	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	3	0.456	7.498	0.300	16.442
7	Fabric Filter	27	0.004	3.616	3.616	903.983

TABLE 5-14
PARTICULATE MATTER AND SO_2 CONTROL SCENARIO RESULTS FOR SAGUARO NP
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		35	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	5	0.550	7.498	0.250	13.632
7	Fabric Filter	35	0.004	3.616	NA	903.996

TABLE 5-15
PARTICULATE MATTER AND SO_2 CONTROL SCENARIO RESULTS FOR SUPERSTITION WA
ST1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		4	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	0	0.249	7.498	1.874	30.111
7	Fabric Filter	4	0.001	3.616	NA	3615.985

TABLE 5-16
CHIRICAHUA WA AND NM PARTICULATE MATTER AND SO_2 CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	69	0.765	7.498	0.109	9.801

TABLE 5-17
GALIURO WA PM AND SO_2 CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 dV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	25	0.456	7.498	0.300	16.442

TABLE 5-18
SAGUARO NP PARTICULATE MATTER AND SO_2 CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	30	0.550	7.498	0.250	13.632

TABLE 5-19
SUPERSTITION WA PARTICULATE MATTER AND SO_2 CONTROL SCENARIO INCREMENTAL ANALYSIS DATA
ST1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	4	0.249	7.498	1.874	30.111

FIGURE 5-17
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Chiricahua WA and NM—Days Reduction
ST1

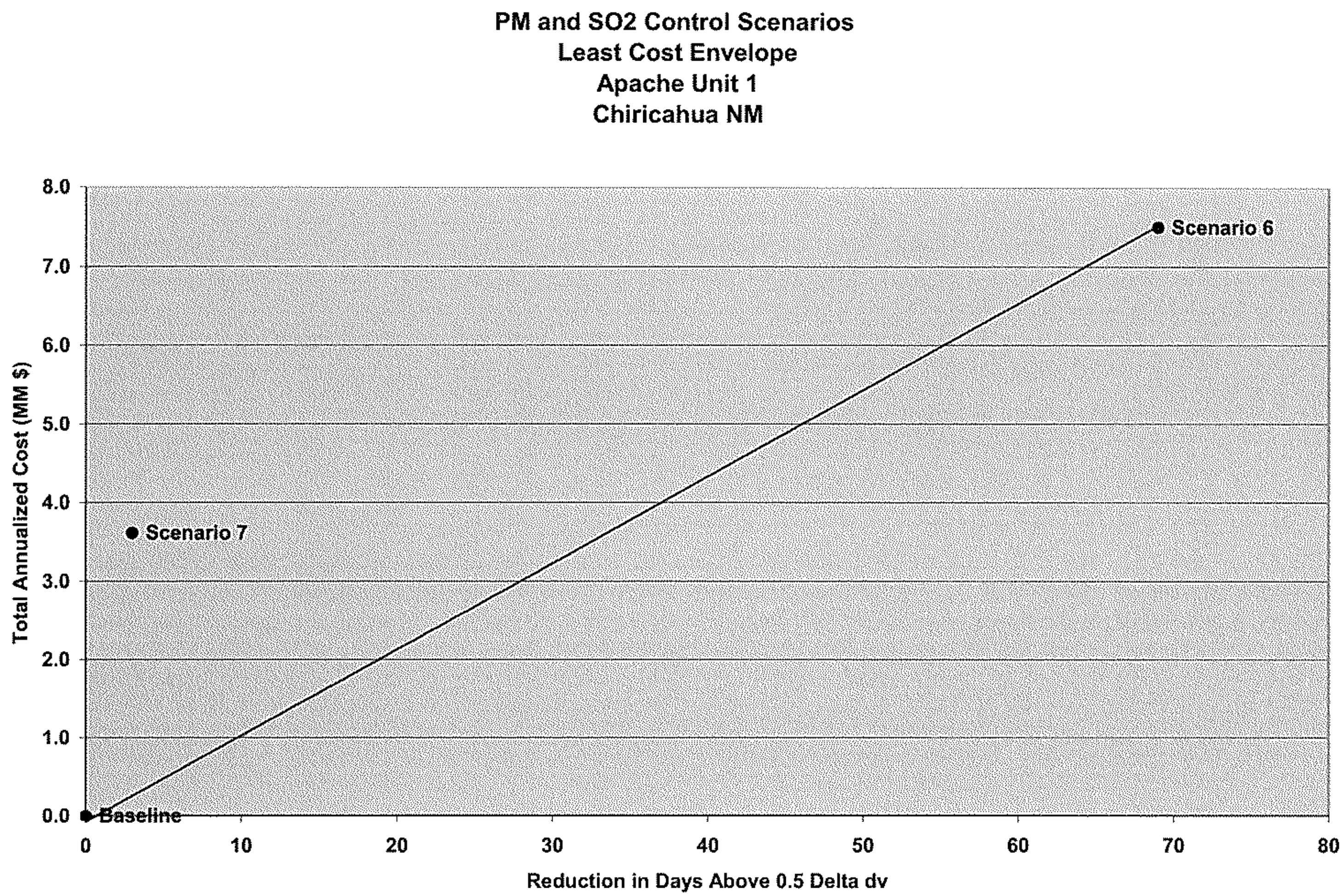


FIGURE 5-18
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Chiricahua WA and NM—98th Percentile Reduction
ST1

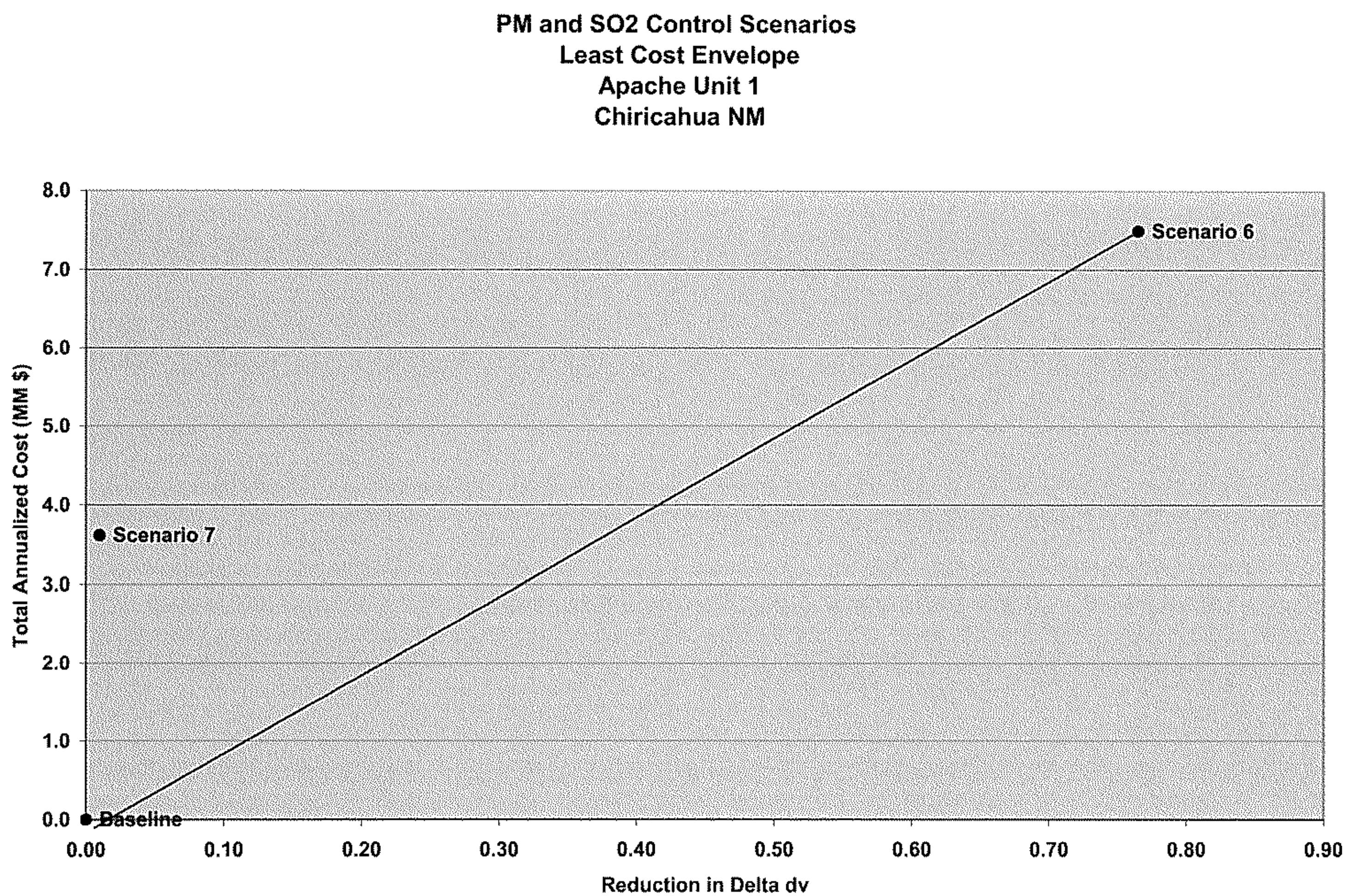


FIGURE 5-19
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Galiuro WA—Days Reduction
ST1

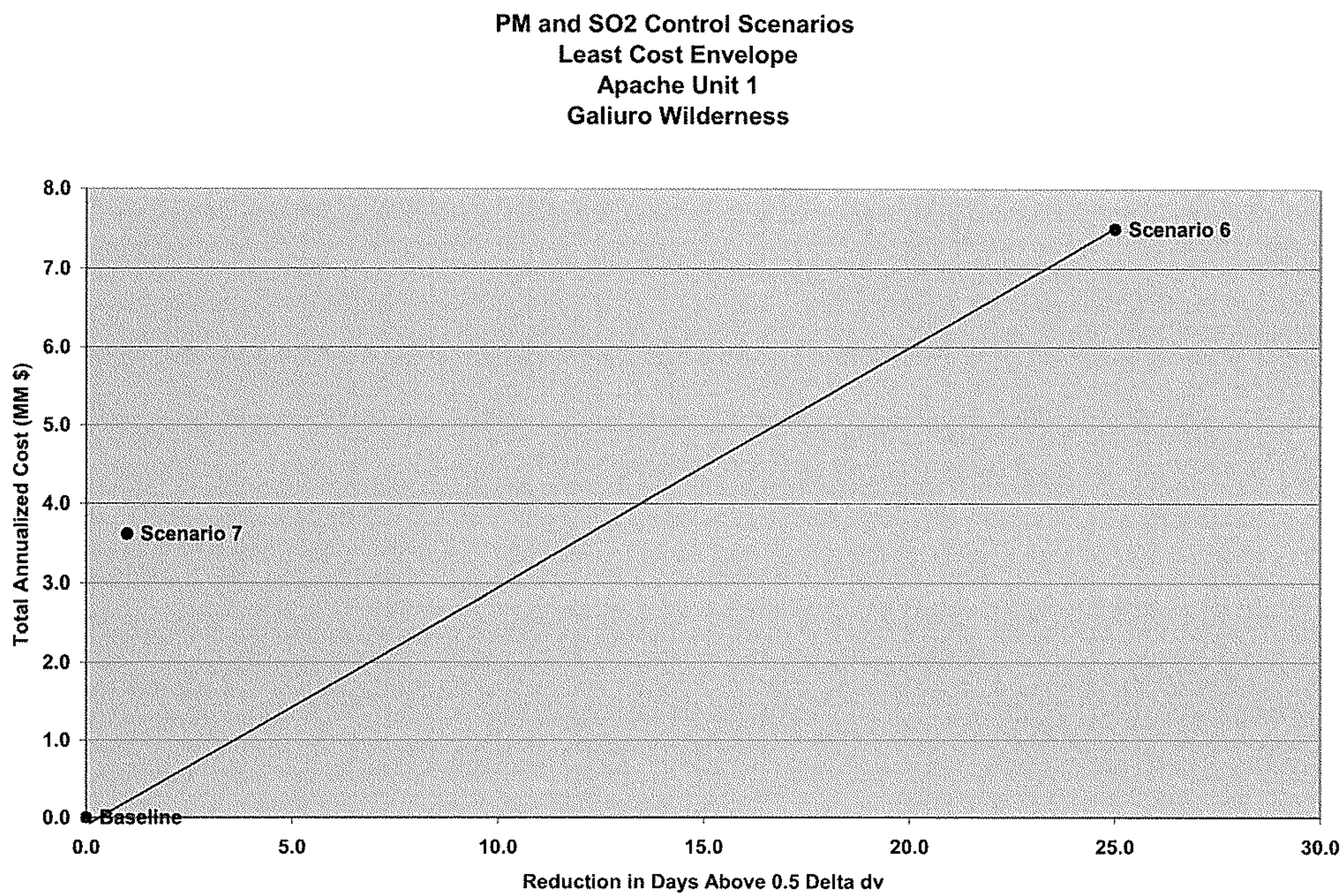


FIGURE 5-20
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Galiuro WA—98th Percentile Reduction
ST1

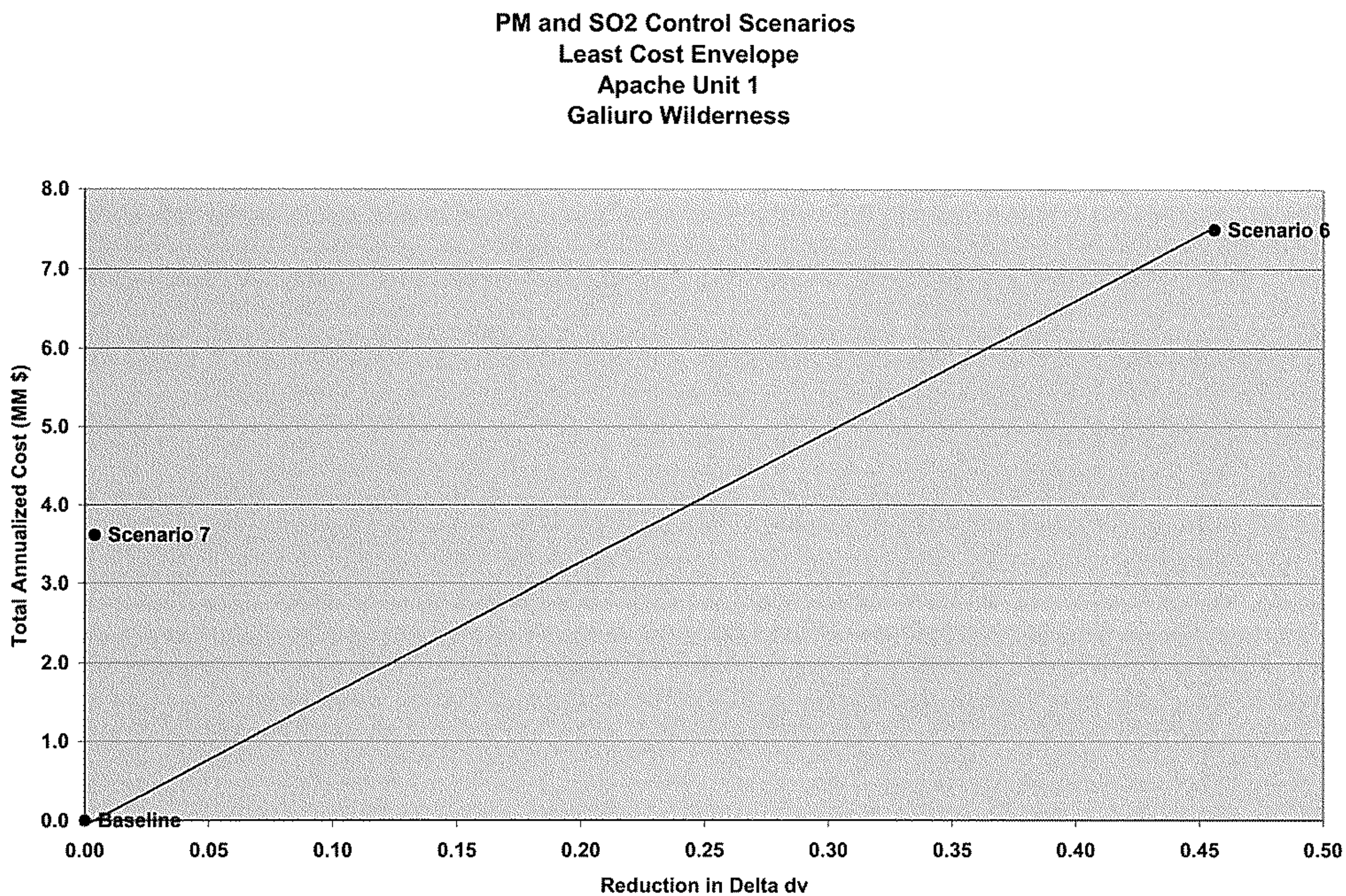


FIGURE 5-21
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Saguaro NP—Days Reduction
ST1

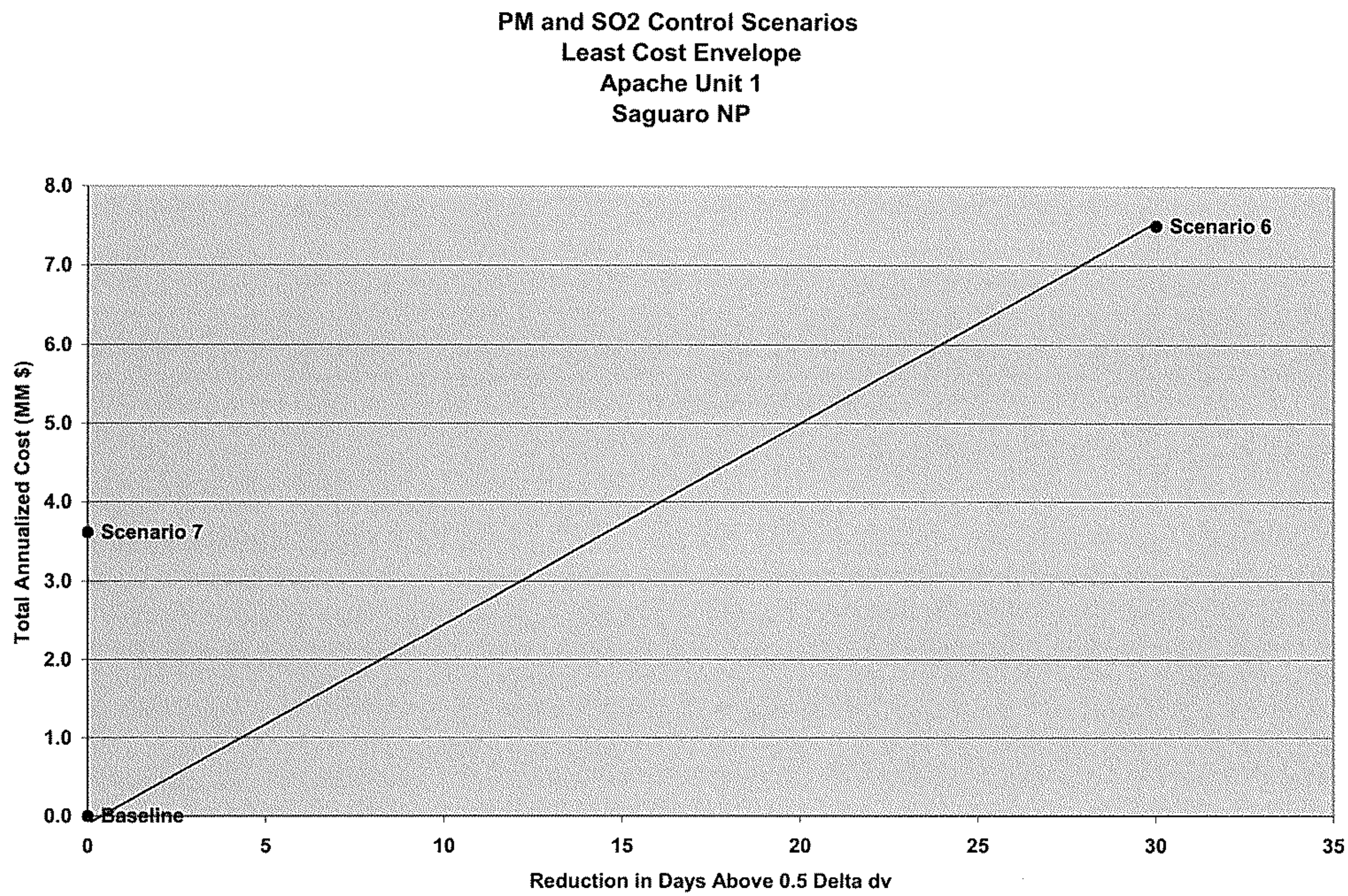


FIGURE 5-22
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Saguaro NP—98th Percentile Reduction
ST1

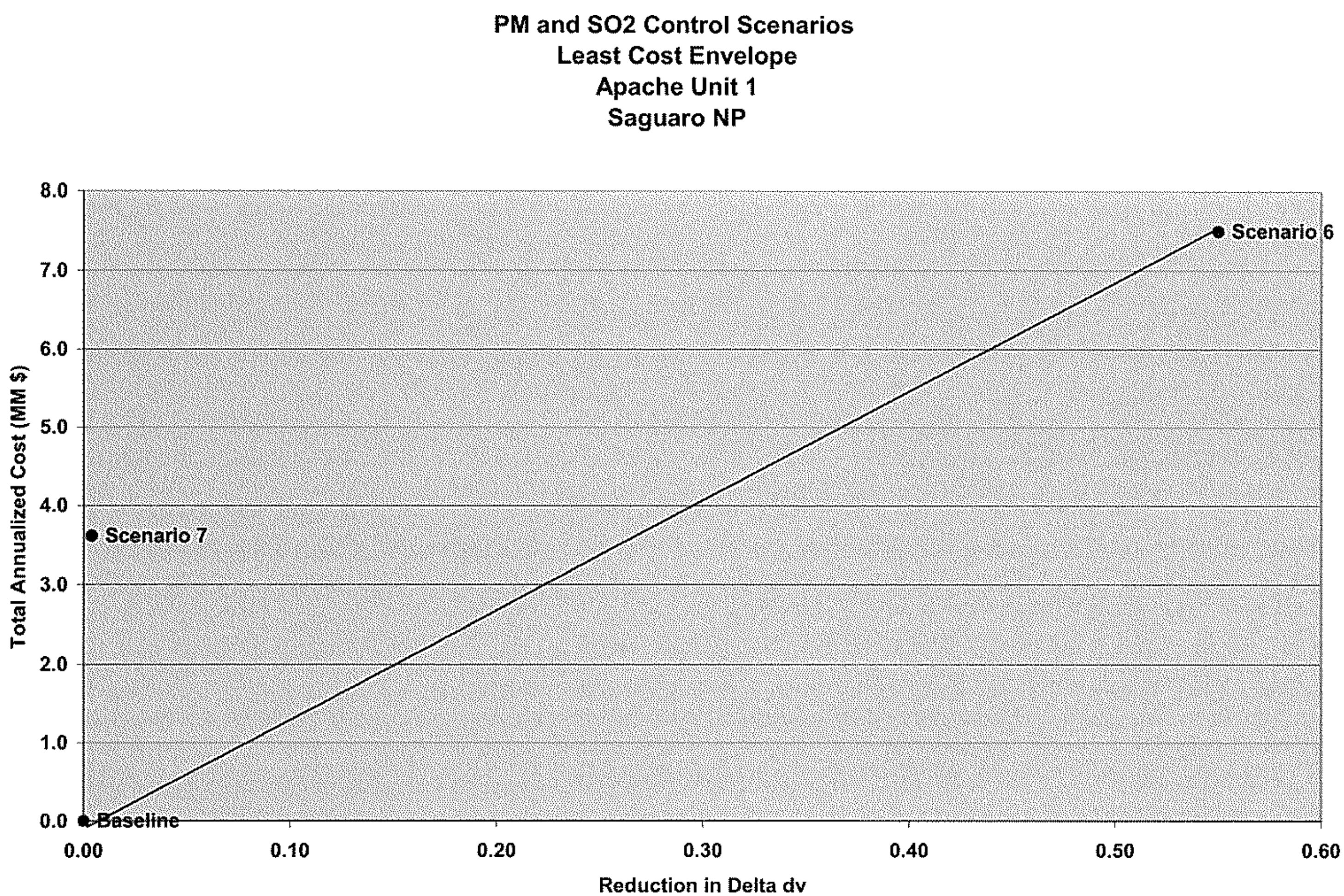


FIGURE 5-23
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Superstition WA—Days Reduction
ST1

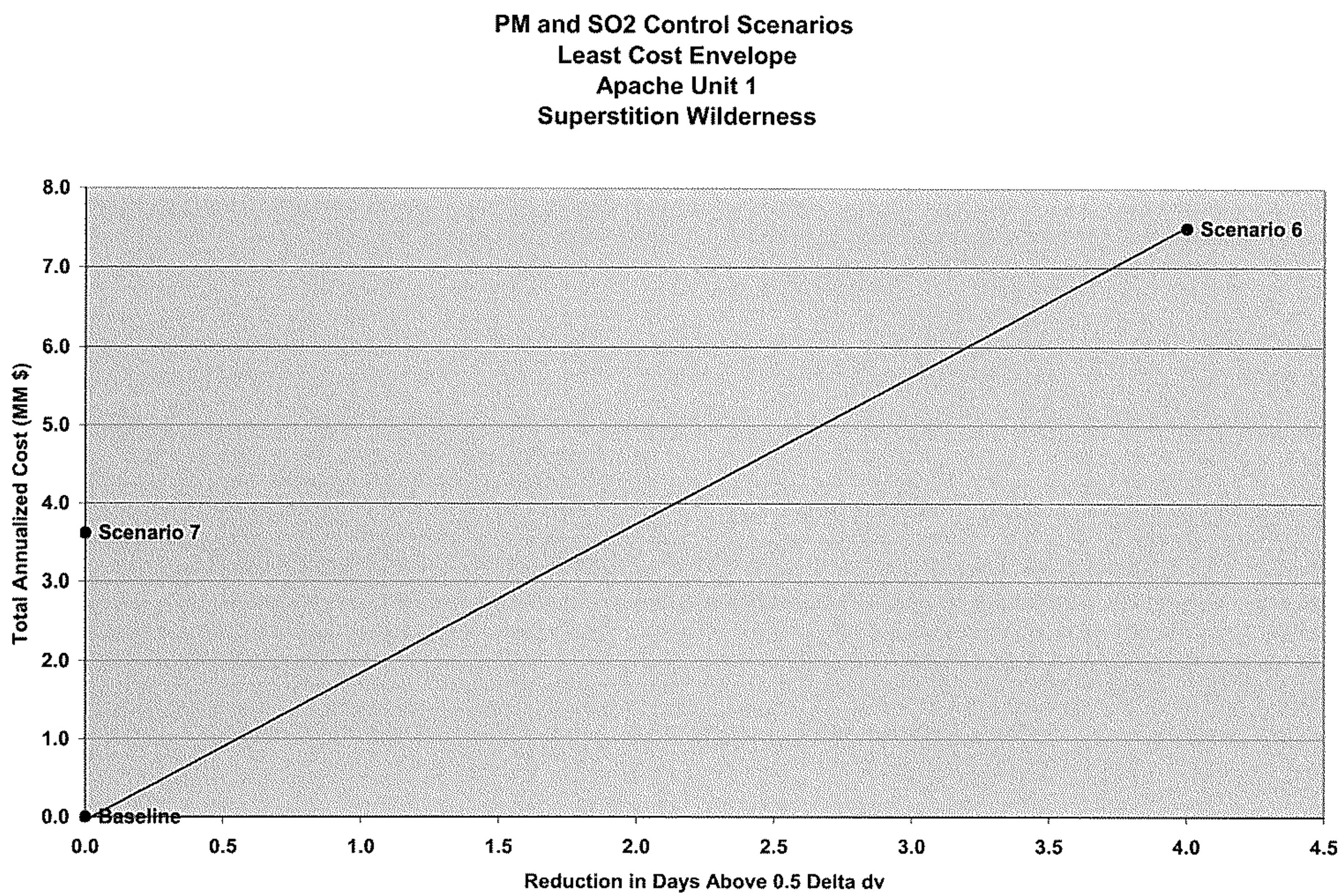
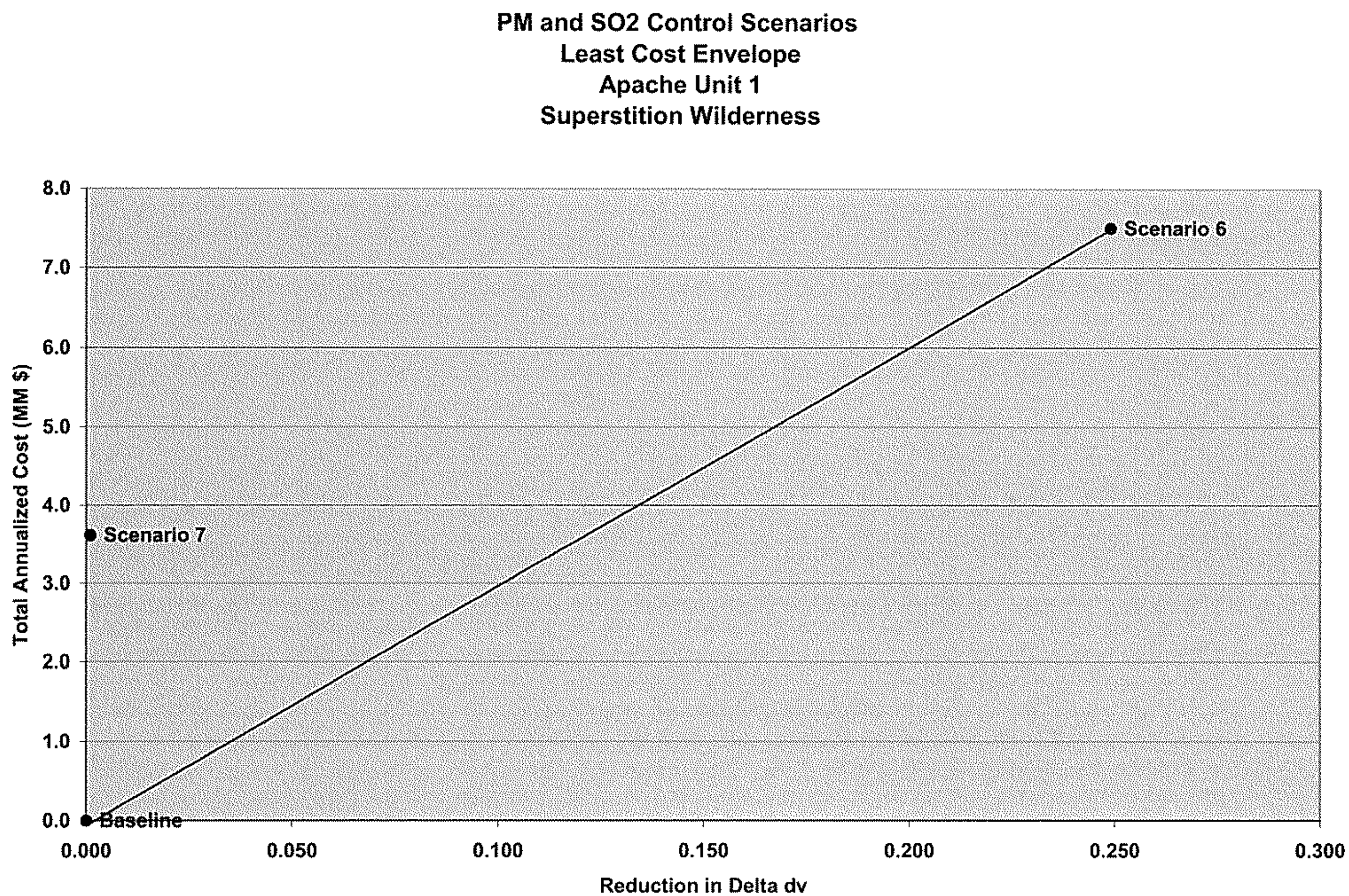


FIGURE 5-24
Particulate Matter and SO_2 Control Scenarios—Least-Cost Envelope Superstition WA—98th Percentile Reduction
ST1



5.3.2 Analysis Results

Results of the least-cost analysis for the various NO_x emission control scenarios, shown in Tables 5-4 through 5-11 and Figures 5-9 through 5-16, confirm the selection of Scenario 1 (LNB with FGR), based on incremental cost and visibility improvements. Scenario 2 (ROFA) shows a small ΔdV improvement over Scenario 1. Scenario 5 (SCR), which also falls on the analysis envelope, has a significant increase in cost effectiveness. All other NO_x control scenarios are excluded on the basis of cost effectiveness.

Although Scenario 1 may be above the cost envelope for many of these analyses, it is still considered a valid and preferred NO_x emission option for the reasons described below. In general, the incremental improvements between Scenario 1 and the Baseline are more significant than those between Scenario 2 and Scenario 1.

Analysis of the NO_x results for the four Class I areas in Tables 5-4 through 5-11 and Figures 5-9 through 5-16 illustrates the conclusions stated above. For Chiricahua WA and NM, the incremental cost differential for Scenario 1 compared to the Baseline is \$2,845,000 per ΔdV, which is slightly less than the incremental cost differential for Scenario 2 compared to the Scenario 1 (\$6,244,000 per ΔdV). The incremental cost effectiveness between Scenario 2 and Scenario 5 shows a significant increase (\$31,148,000 per ΔdV).

For these NO_x control scenarios, the incremental ΔdV improvements between Scenario 1 and the Baseline at Chiricahua (0.194 dV) are more significant than those between Scenario 2 and Scenario 1 (0.062 dV). Although both these results include Baseline emissions for PM_{10} and SO_2, these values are well below the 0.5 dV level where a source is considered to be contributing to impairment (40 CFR Part 51 Appendix Y).

Table 5-20 demonstrates that similar impacts were predicted at the other three Class I areas. This table, along with Figure 5-9, shows that Scenario 1 is estimated to have reduced the days at Chiricahua with impacts above 0.5 dV by 11 days with no additional improvement for Scenario 2. Therefore, because of the significant improvements related to Scenario 1, Scenario 1 represents NO_x control BART for ST1.

TABLE 5-20
INCREMENTAL IMPROVEMENTS
ST1

	Scenario 1 vs. Baseline		Scenario 2 vs. Scenario 1	
Class I Area	Incremental Reduction in Days Above 0.5 dV (Days)	Incremental ΔdV Reductions (dV)	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)
Chiricahua	11	0.194	0	0.062
Galiuro	3	0.084	9	0.064
Saguaro	6	0.117	0	0.105
Superstition	0	0.026	0	0.021

Improvements to ΔdV impacts from particulate matter and SO_2 controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs at Chiricahua WA and NM related to adding a fabric filter and SDA are quite high ($9,801,000 per ΔdV). Impacts from the combustion of No. 2 fuel oil or natural gas without particulate matter or SO_2 emission controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

5.4 Recommendations

5.4.1 NO_x Emission Control

Based on the analysis conducted, new LNB with FGR is recommended as BART for ST1, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no non-air quality environmental impacts.

5.4.2 SO_2 Emission Control

Based on the analysis conducted, no additional SO_2 emission control is recommended while combusting natural gas or No. 2 fuel oil.

5.4.3 PM_{10} Emission Control

Based on the analysis conducted, no additional PM_{10} emission control is recommended while combusting natural gas or No. 2 fuel oil.

5.5 Just-noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate only dV differences of approximately 1.5 to 2.0 dV or more are perceptible by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the scenarios. Thus the results indicate that even though many millions of dollars will be spent, only minimal, if any, noticeable visibility improvements may result.

Finally, it should be noted that none of the data were corrected for natural obscuration where water in various forms (fog, clouds, snow, or rain) or other naturally caused aerosols obscure the atmosphere. During the period of 2001 through 2003, there were several mega-wildfires that lasted for many days and could have had a significant impact of background visibility in these Class I areas. If natural obscuration were to reduce the reduction in visibility impacts modeled for the ST1 facility, the effect would be to increase the costs per ΔdV reduction that are presented in this report.

Section 6.0
References

6.0 References

Colorado Department of Public Health and Environment (CDPHE) 2005. *CALMET/CALPUFF BART Protocol for Class I Federal Area Individual Source Attribution Visibility Impairment Modeling Analysis.* Colorado Department of Public Health and Environment, Air Pollution Control Division, Denver, Colorado. October 24.

40 CFR Part 51 2005. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule* (Federal Register, July 6, 2005, pg 39104).

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Western Regional Air Partnership (WRAP). 2006. *Draft Final Modeling Protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States.* Western Regional Air Partnership, Air Quality Modeling Forum, Regional Modeling Center, August 15, 2006.

Appendix A
Economic Analysis

APPENDIX A

Economic Analysis

ECONOMIC ANALYSIS SUMMARY

Apache Unit 1 (ST1) — **Boiler Design:** Front Wall Fired Gas/Oil

Parameter	Current Operation	NOx Control					SO2 Control	PM Control
		ROFA	LNB w/FGR	LNB w/FGR & SNCR	ROFA w/Rotamix	LNB w/SCR	SDA	Fabric Filter
Case	1	2	3	4	5	6	7	8
NOx Emission Control System	None	ROFA	LNB w/FGR	LNB w/FGR & SNCR	ROFA w/Rotamix	LNB w/SCR	SDA	None
SO2 Emission Control System	None	None	None	None	None	None	None	Fabric Filter
PM Emission Control System	None	None	None	None	None	None	None	None
TOTAL INSTALLED CAPITAL COST ($)	0	2,700,000	1,184,000	4,584,000	4,457,000	25,500,000	20,000,000	20,000,000
Including Other Owner Costs ($)	0	4,725,000	2,072,000	5,730,000	7,799,750	31,875,000	---	---
FIRST YEAR O&M COST ($)								
Operating Labor ($)	0	12,750	12,750	17,000	17,000	25,500	51,000	34,000
Maintenance Material ($)	0	25,500	25,500	34,000	34,000	51,000	102,000	68,000
Maintenance Labor ($)	0	12,750	12,750	17,000	17,000	25,500	51,000	34,000
Administrative Labor ($)	0	0	0	0	0	0	0	0
TOTAL FIXED O&M COST	0	51,000	51,000	68,000	68,000	102,000	204,000	136,000
Reagent Cost	0	0	0	32,813	32,813	40,238	156,752	0
SCR Catalyst / FF Bag Cost	0	0	0	0	0	127,500	0	45,760
Electric Power Cost	0	93,739	152,643	15,264	93,739	76,322	71,832	71,832
Waste Disposal Cost	0	0	0	0	0	0	86,775	0
TOTAL VARIABLE O&M COST	0	93,739	152,643	48,077	126,552	244,058	315,359	117,592
TOTAL FIRST YEAR O&M COST	0	144,739	203,643	116,077	194,552	346,058	519,359	253,592
FIRST YEAR DEBT SERVICE ($)	0	794,354	348,339	963,312	1,311,273	5,358,740	3,362,346	3,362,346
TOTAL FIRST YEAR COST ($)	0	939,093	551,982	1,079,389	1,505,825	5,704,798	3,881,706	3,615,938
Power Consumption (MW)	0.0	0.5	0.9	0.1	0.5	0.4	0.4	0.4
Annual Power Usage (Million kW-Hr/Yr)	0.0	1.9	3.1	0.3	1.9	1.5	1.4	1.4
CONTROL COST ($/Ton Removed)								
NOx Removal Rate (%)	0.0%	46.8%	50.2%	63.5%	63.5%	76.7%	0.0%	0.0%
NOx Removed (Tons/Yr)	0	278	297	376	376	455	0	0
First Year Average Control Cost ($/Ton NOx Rem.)	0	3,382	1,856	2,870	4,004	12,542	0	0
Incremental Control Cost ($/Ton NOx Removed)	0	(19,659) 2-3	1,856 3-1	1,425 4-2	---	53,311 6-5	0	0
SO2 Removal Rate (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	89.0%	0.0%
SO2 Removed (Tons/Yr)	0	0	0	0	0	0	1,587	0
First Year Average Control Cost ($/Ton SO2 Rem.)	0	0	0	0	0	0	2,446	0
Incremental Control Cost ($/Ton SO2 Removed)	Base	0	0	0	0	0	2,446 7-1	0
PM Removal Rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	79.6%
PM Removed (Tons/Yr)	0	0	0	0	0	0	0	116
First Year Average Control Cost ($/Ton PM Rem.)	0	0	0	0	0	0	0	24,916
Incremental Control Cost ($/Ton PM Removed)	Base	0	0	0	0	0	0	31,284 8-1
PRESENT WORTH COST ($)	0	10,118,788	6,149,881	11,544,716	16,161,331	60,560,076	41,691,020	38,443,912

For the other owner costs a factor of 1.75 was used for everything except the SCR & SNCR to represent balance of plant cost, electrical costs, AFUDC etc.
For the SCR & SNCR a factor of 1.25 was used because the material cost of $300/kW & $40/kW respectivly from the CH2M HILL database already included the balance of plant and a few other costs

INPUT CALCULATIONS

Apache Unit 1 (ST1) Boiler Design: Front Wall Fired Gas/Oil

Parameter	Current Operation	NOx Control					SO2 Control	PM Control	Comments
		ROFA	LNB w/FGR	LNB w/FGR & SNCR	ROFA w/Rotamix	LNB w/SCR	SDA	Fabric Filter	
Case	1	2	3	4	5	6	7	8	
NOx Emission Control System	None	ROFA	LNB w/FGR	LNB w/FGR & SNCR	ROFA w/Rotamix	LNB w/SCR	SDA	None	
SO2 Emission Control System	None	None	None	None	None	None	None	Fabric Filter	
PM Emission Control System	None	None	None	None	None	None	None	None	
Unit Design and Coal Characteristics									
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	
Net Power Output (kW)	85,000	85,000	85,000	85,000	85,000	85,000	85,000	85,000	
Net Plant Heat Rate (Btu/kW-Hr)	12,900	12,900	12,900	12,900	12,900	12,900	12,900	12,900	
Boiler Fuel	No. 6 Fuel Oil	No. 6 Fuel Oil	No. 6 Fuel Oil	No. 6 Fuel Oil	No. 6 Fuel Oil	No. 6 Fuel Oil	No. 6 Fuel Oil	No. 6 Fuel Oil	
Fuel Heating Value (Btu/Lb)	20,119	20,119	20,119	20,119	20,119	20,119	20,119	20,119	
Fuel Sulfur Content (wt.%)	0.900%	0.900%	0.900%	0.900%	0.900%	0.900%	0.900%	0.900%	
Fuel Ash Content (wt.%)	0.040%	0.040%	0.040%	0.040%	0.040%	0.040%	0.040%	0.040%	
Boiler Heat Input, each (MMBtu/Hr)	1,097	1,097	1,097	1,097	1,097	1,097	1,097	1,097	
Coal Flow Rate (Lb/Hr)	54,502	54,502	54,502	54,502	54,502	54,502	54,502	54,502	
(Ton/Yr)	97,874	97,874	97,874	97,874	97,874	97,874	97,874	97,874	
(MMBtu/Yr)	3,938,189	3,938,189	3,938,189	3,938,189	3,938,189	3,938,189	3,938,189	3,938,189	
Emissions									
Uncontrolled SO2 (Lb/Hr)	993	993	993	993	993	993	993	993	
(Lb/MMBtu)	0.906	0.906	0.906	0.906	0.906	0.906	0.906	0.906	
(Lb Moles/Hr)	15.51	15.51	15.51	15.51	15.51	15.51	15.51	15.51	
(Tons/Yr)	1,784	1,784	1,784	1,784	1,784	1,784	1,784	1,784	
SO2 Removal Rate (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	89.0%	0.0%	
(Lb/Hr)	0	0	0	0	0	0	884	0	
(Ton/Yr)	0	0	0	0	0	0	1,587	0	
SO2 Emission Rate (Lb/Hr)	993	993	993	993	993	993	110	993	
(Lb/MMBtu)	0.906	0.906	0.906	0.906	0.906	0.906	0.10	0.906	
(Ton/Yr)	1,784	1,784	1,784	1,784	1,784	1,784	197	1,784	
Uncontrolled NOx (Lb/Hr)	330	330	330	330	330	330	330	330	
(Lb/MMBtu)	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	
(Lb Moles/Hr)	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	
(Tons/Yr)	593	593	593	593	593	593	593	593	
NOx Removal Rate (%)	0.0%	46.8%	50.2%	63.5%	63.5%	76.7%	0.0%	0.0%	
(Lb/Hr)	0	155	166	209	209	253	0	0	
(Lb Moles/Hr)	0.00	5.15	5.52	6.98	6.98	8.44	0.00	0	
(Ton/Yr)	0	278	297	376	376	455	0	0	
NOx Emission Rate (Lb/Hr)	330	175	164	121	121	77	330	330	
(Lb/MMBtu)	0.30	0.16	0.15	0.11	0.11	0.07	0.30	0.30	
(Ton/Yr)	593	315	295	217	217	138	593	593	
Uncontrolled Fly Ash (Lb/Hr)	65	81	81	81	81	81	81	81	
(Lb/MMBtu)	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	
(Lb Moles/Hr)	2.2	2.7	2.7	2.7	2.7	2.7	2.7	2.7	
(Tons/Yr)	116	145	145	145	145	145	145	145	
Fly Ash Removal Rate (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	79.65%	
(Lb/Hr)	-16	0	0	0	0	0	0	64	
(Ton/Yr)	-29	0	0	0	0	0	0	116	
Fly Ash Emission Rate (Lb/Hr)	81	81	81	81	81	81	81	16	
(Lb/MMBtu)	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.015	
(Ton/Yr)	145	145	145	145	145	145	145	30	

Parameter	Current Operation	NOx Control					SO2 Control	PM Control	Comments
		ROFA	LNB w/FGR	LNB w/FGR & SNCR	ROFA w/Rotamix	LNB w/SCR	SDA	Fabric Filter	
Case	1	2	3	4	5	6	7	8	
General Plant Data									
Annual Operation (Hours/Year)	3,592	3,592	3,592	3,592	3,592	3,592	3,592	3,592	
Annual On-Site Power Plant Capacity Factor	41%	0.41	0.41	0.41	0.41	0.41	0.41	0.41	
Economic Factors									
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Plant Economic Life (Years)	8	8	8	8	8	8	8	8	
Installed Capital Costs (including owner costs)									
NOx Emission Control System ($2007)	0	4,725,000	2,072,000	5,730,000	7,799,750	31,875,000	0	0	
SO2 Emission Control System ($2007)	0	0	0	0	0	0	20,000,000	20,000,000	
PM Emission Control System ($2007)	0	0	0	0	0	0	0	0	
Total Emission Control Systems ($2007)	0	4,725,000	2,072,000	5,730,000	7,799,750	31,875,000	20,000,000	20,000,000	
NOx Emission Control System ($/kW)	0	56	24	67	92	375	0	0	
SO2 Emission Control System ($/kW)	0	0	0	0	0	0	235	235	
PM Emission Control System ($/kW)	0	0	0	0	0	0	0	0	
Total Emission Control Systems ($/kW)	0	56	24	67	92	375	235	235	
Total Fixed Operating & Maintenance Costs									
Operating Labor ($)	0	12,750	12,750	17,000	17,000	25,500	51,000	34,000	
Maintenance Material ($)	0	25,500	25,500	34,000	34,000	51,000	102,000	68,000	
Maintenance Labor ($)	0	12,750	12,750	17,000	17,000	25,500	51,000	34,000	
Administrative Labor ($)	0	0	0	0	0	0	0	0	
Total Fixed O&M Cost ($)	0	51,000	51,000	68,000	68,000	102,000	204,000	136,000	
Annual Fixed O&M Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Reagent Cost	None	None	None	Urea	Urea	Anhydrous NH3	Lime	0	
Unit Cost ($/Ton)	0.00	0.00	0.00	370.00	370.00	400.00	91.25	0.00	
($/Lb)	0.000	0.000	0.000	0.185	0.185	0.200	0.046	0.000	
Molar Stoichiometry	0.00	0.00	0.00	0.45	0.45	1.00	1.10	0.00	
Reagent Purity (Wt.%)	100%	100%	100%	100%	100%	100%	100%	90%	
Reagent Usage (Lb/Hr)	0	0	0	49	49	56	957	0	
First Year Reagent Cost ($)	0	0	0	32,813	32,813	40,236	156,752	0	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost						SCR Catalyst		Bags	
Annual SCR Catalyst (m3) / No. FF Bags	0	0	0	0	0	43	0	440	
SCR Catalyst ($/m3) / Bag Cost ($/ea.)	3,000	3,000	3,000	3,000	3,000	3,000	3,000	104	
First Year SCR Catalyst / Bag Replace. Cost ($)	0	0	0	0	0	127,500	0	45,760	
Annual SCR Catalyst / Bag Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Auxiliary Power Cost									
Auxiliary Power Requirement (% of Plant Output)	0.00%	0.61%	1.00%	0.10%	0.61%	0.50%	0.47%	0.47%	
(MW)	0.00	0.52	0.85	0.09	0.52	0.43	0.40	0.40	
Unit Cost ($2007/MW-Hr)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	
First Year Auxiliary Power Cost ($)	0	93,739	152,643	15,264	93,739	76,322	71,832	71,832	
Annual Power Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

Appendix B
BART Protocol

APPENDIX B

BART Protocol

Modeling Protocol for BART Control Technology Improvement Modeling Analyses for the AEPCO Apache Generating Station

Prepared for

AEPCO
Arizona Electric Power Cooperative, Inc.
A Touchstone Energy® Cooperative

Prepared by

CH2MHILL

July 2007

Contents

SECTION 1.0

Introduction

This document presents a modeling protocol for estimating the degree of visibility improvement from Best Available Retrofit Technology (BART) control technology options for the Arizona Electric Power Cooperative (AEPCO) Apache Generating Station Steam Units 1, 2 and 3. The Arizona Department of Environmental Quality (ADEQ) has identified that these three boiler units at the Apache Generating Station are BART eligible and must perform a Phase II BART analysis.

This protocol outlines the proposed approach for the modeling analysis for the Apache Generating Station. To a large extent, this protocol follows the methodology outlined in the Western Regional Air Partnership (WRAP) protocol for performing BART analyses (WRAP 2006). Any proposed deviations from that methodology are documented in this protocol. Section 2.0 describes the modeling system (CALPUFF) that will be used for the analyses. Sections 3.0 and 4.0 describe the proposed methodology for the CALMET meteorological model and the CALPUFF model, respectively. Section 5.0 presents a summary of the proposed approach for the CALPOST post-processor and Section 6.0 presents a brief description of the final report format for submittal to ADEQ. Section 7.0 contains a list of references cited in the protocol document.

SECTION 2.0

Model Selection

CH2M HILL will use the CALPUFF modeling system to assess the visibility impacts at Class I areas. Workgroups that represent the interests of the Federal Land Managers (FLM) recommend that an analysis of Class I area air quality and air quality related values (AQRVs) be performed for major sources located more than 50 km from these areas (USEPA 1998). The CALPUFF model is commonly recommended for these types of regulatory analyses.

The CALPUFF modeling system includes the CALMET meteorological model, a Gaussian puff dispersion model (CALPUFF) with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system will be applied in a full, refined mode.

CH2M HILL will use the latest version (Version 6) of the CALPUFF modeling system preprocessors and models in lieu of the EPA-approved versions (Version 5). The Federal Land Managers (FLMs) and others have noted that the EPA-approved Version 5 contained errors and that a newer version should be used. In addition, Version 6 was used in the WRAP exemption modeling. Consequently, it was decided to use the latest (as of April, 2006) version of the CALPUFF modeling system (available at www.src.com):

- CALMET Version 6.211 Level 060414
- CALPUFF Version 6.112 Level 060412

SECTION 3.0

CALMET Methodology

3.1 Dimensions of the Modeling Domain

CH2M HILL will define domains for Mesoscale Model data (MM5), CALMET, and CALPUFF that will be slightly different than those established for the Arizona BART modeling in WRAP 2006. In addition, the CALMET and CALPUFF Lambert Conformal Conic (LCC) map projection will be based on a central meridian of 110 W rather than 97 W. This will put the central meridian near the center of the domain.

CH2M HILL will use the CALMET model to generate three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. A CALMET modeling domain has been defined to allow for at least a 50-km buffer around all Class I areas within 300 km of the Apache Generating Station. Grid resolution for this domain will be 4-km. Figure 3-1 shows the extent of the proposed modeling domain.

The technical options recommended in WRAP 2006 will be used for CALMET. Vertical resolution of the wind field will include eleven layers, with vertical cell face heights as follows (in meters):

- 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 5000

Also, following WRAP 2006, the maximum over-land mixing height (ZIMAX) will be set to 4500 meters based on the Colorado Department of Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (CDPHE, 2005). The CDPHE analysis suggests mixing heights in the Denver area are often well above the CALMET default value of 3000 meters during the summer. For example, on some summer days, ozone levels are elevated all the way to 6000 meters MSL or beyond during some meteorological regimes, including some regimes associated with high ozone episodes. It is assumed that, like in Denver, mixing heights in excess of the 3,000 m AGL CALMET default maximum would occur in the domains considered for this analysis.

Table 3-1 lists the key user-specified options.

Figure 3-1
CALMET and CALPUFF Domains

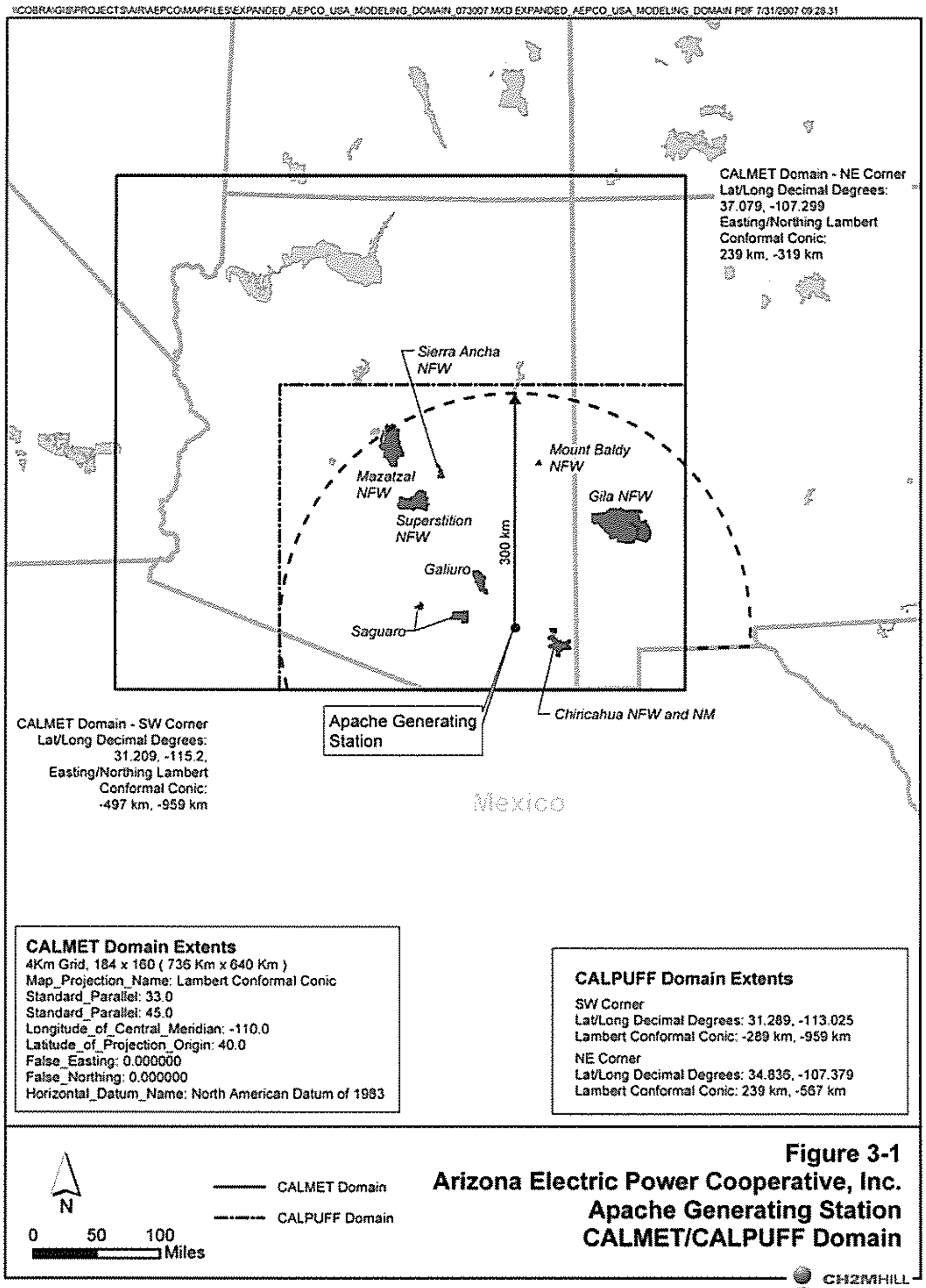

TABLE 3-1
User-Specified CALMET Options

Description	CALMET Input Parameter	Value
	CALMET Input Group 2	
Map projection	PMAP	Lambert Conformal (LCC)
Grid spacing	DGRIDKM	4
Number vertical layers	NZ	11
Top of lowest layer (m)		20
Top of highest layer (m)		5000
	CALMET Input Group 4	
Observation mode	NOOBS	1
	CALMET Input Group 5	
Prognostic or MM-FDDA data switch	IPROG	14
Max surface over-land extrapolation radius (km)	RMAX1	50
Max aloft over-land extrapolations radius (km)	RMAX2	100
Radius of influence of terrain features (km)	TERRAD	10
Relative weight at surface of Step 1 field and obs	R1	100
Relative weight aloft of Step 1 field and obs	R2	200
	CALMET Input Group 6	
Maximum over-land mixing height (m)	ZIMAX	4500

3.2 CALMET Input Data

CH2M HILL will run the CALMET model to produce three years of analysis: 2001, 2002, and 2003. CH2M HILL will use MM5 data as the basis for the CALMET wind fields. The horizontal resolution of the MM5 data is 36-km.

For 2001, CH2M HILL will use MM5 data at 36-km resolution that were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for the EPA. For 2002, CH2M HILL will use 36-km MM5 data obtained from Alpine Geophysics, originally developed for WRAP. Data to be used for 2003 (also from Alpine Geophysics), at 36-km resolution, were developed by the Wisconsin Department of Natural Resources, the Illinois

Environmental Protection Agency, and the Lake Michigan Air Directors Consortium (Midwest RPO).

The MM5 data will be used as input to CALMET as the "initial guess" wind field. The initial guess field will be adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, and then further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001-2003 will be obtained from the National Climatic Data Center (NCDC). In addition, concurrent surface data collected at the Apache Generating Station will be included. CH2M HILL will process data for all stations from the National Weather Service's (NWS) Automated Surface Observing System (ASOS) network that are in the domain. The surface data will be obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website will be used to convert the DATSAV3 files to CD-144 format for input to the SMERGE preprocessor and CALMET.

Land use and terrain data will be obtained from the U.S. Geological Survey (USGS). Land use data will be obtained in Composite Theme Grid (CTG) format from the USGS, and the Level I USGS land use categories will be mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index will be computed from the land use values. Terrain data will be taken from USGS 1-degree Digital Elevation Model (DEM) data, which are primarily derived from USGS 1:250,000 scale topographic maps. Missing land use data will be filled with a value that is appropriate for the missing area.

Precipitation data will be ordered from the National Climatic Data Center (NCDC). All available data in fixed-length, TD-3240 format will be ordered for the modeling domain. The list of available stations and stations that have collected complete data varies by year, but CH2M HILL will process all available stations/data within the domain for each year. Precipitation data will be prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Following the methodology recommended in WRAP 2006, no observed upper-air meteorological observations will be used as they are redundant to the MM5 data, and may introduce spurious artifacts in the wind fields. In the development of the MM5 data, the twice daily upper-air meteorological observations are used as input with the MM5 model. The MM5 estimates are nudged to the upper-air observations as part of the Four Dimensional Data Assimilation (FDDA). This results in higher temporal (hourly vs. 12-hour) and spatial (36 km vs. ~300 km) resolution for the upper-air meteorology in the MM5 field. These MM5 data are more dynamically balanced than those contained in the upper-air observations. Therefore the use of the upper-air observations with CALMET is not needed, and, in fact, will upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities.

3.3 Validation of CALMET Wind Field

CH2M HILL will use the CalDESK data display and analysis system (v2.97, Enviromodeling Ltd.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. We will use observed weather conditions, as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration (NOAA) Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/rescue/dwm/data_rescue_daily_weather_maps.html), to compare to the CalDESK displays.

SECTION 4.0

CALPUFF Methodology

4.1 CALPUFF Modeling

CH2M HILL will drive the CALPUFF model with the meteorological output from CALMET over the CALPUFF modeling domain (Figure 3-1). The CALPUFF model will be used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios.

4.1.1 Background Ozone and Ammonia

Hourly values of background ozone concentrations will be used by CALPUFF for the calculation of SO_2 and NO_X transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL will use the hourly ozone data generated for the WRAP BART analysis for 2001, 2002, and 2003.

For periods of missing hourly ozone data, the chemical transformation will rely on a monthly default value of 80 ppb. Background ammonia will be set to 1 ppb as recommended in WRAP 2006.

4.1.2 Stack Parameters

The baseline stack parameters will be the same as those used in the WRAP-RMC exemption modeling. Post-control stack parameters will reflect any anticipated changes from operation of the control technology alternatives that are being evaluated.

4.1.3 Pre-Control Emission Rates

Pre-control emission rates will reflect normal maximum capacity 24-hour emissions that may occur under the source's current permit. The emission rates will reflect actual emissions under normal operating conditions. As described by the EPA in the *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule* (40 CFR Part 51; July 6, 2005, pg 39129):

> *The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high-capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used…*

CH2M HILL will use available CEM data to determine the baseline 24-hour emission rates. Data will reflect operations from 2002 through 2006.

Although the WRAP Exemption Modeling evaluated emissions of NOx, SO2, and PM2.5, particulate matter speciation data from the USEPA or National Park Service are proposed for this analysis (USEPA 2007, NPS 2007). Therefore emissions will be modeled for the following species:

- Sulfur dioxide (SO_2)
- Nitrogen oxides (NO_x)
- Coarse particulate ($PM_{2.5} <$ diameter $\leq PM_{10}$)
- Fine particulate (diameter $\leq PM_{2.5}$)
- Elemental carbon (EC)
- Organic aerosols (SOA)
- Sulfates (SO4)

4.1.4 Post Control Emission Rates

Post-control emission rates will reflect the effects of the emissions control scenario under consideration. Modeled pollutants will be the same as listed for the pre-control scenario.

4.1.5 Modeling Process

The CALPUFF modeling for the control technology options will follow this sequence:

- Model pre-control (baseline) emissions
- Determine the degree of visibility improvement
- Model other control scenarios if applicable
- Determine the degree of visibility improvement
- Factor visibility results into BART "5-step" evaluation

4.2 Receptor Grids and Coordinate Conversion

The TRC COORDS program will be used to convert the latitude/ longitude coordinates to LCC coordinates for the meteorological stations and source locations. The USGS conversion program PROJ (version 4.4.6) will be used to convert the National Park Service (NPS) receptor location data from latitude/longitude to LCC.

For the Class I areas that are within 300 km of the Apache Generating Station, discrete receptors for the CALPUFF modeling will be taken from the NPS database for Class I area modeling receptors. The entire area of each Class I area that is within or intersects the 300 km circle (Figure 3-1) will be included in the modeling analysis. The following lists the Class I areas that will be modeled for the Apache Generating Station:

- Chiricahua Wilderness and National Monument
- Galiuro Wilderness
- Saguaro National Park
- Gila Wilderness
- Superstition Wilderness
- Mount Baldy Wilderness
- Sierra Ancha Wilderness
- Mazatzal Wilderness

SECTION 5.0

Visibility Post-processing

5.1 CALPOST

The CALPOST processor will be used to determine 24-hour average visibility results. Output will be specified in deciview (dv) units.

Calculations of light extinction will be made for each pollutant modeled. The sum of all extinction values will be used to calculate the delta-dv change relative to natural background. Default extinction coefficients for each species, as shown below, will be used.

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST visibility Method 6 (MVISBK=6) will be used for the determination of visibility impacts. Monthly average relative humidity factors [f(RH)] will be used in the light extinction calculations to account for the hygroscopic characteristic of sulfate and nitrate particles. Monthly f(RH) values will be the same as the Class I area specific values used in the WRAP-RMC BART modeling.

The natural background conditions as a reference for determination of the delta-dv change will represent the average natural concentration for western Class I areas. Table 5-1 lists the annual average species concentrations from the EPA Guidance.

TABLE 5-1
Average Natural Levels of Aerosol Components

Aerosol Component	Average Natural Concentration ($\mu g/m^3$) for Western Class I Areas
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

Note: Taken from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.

SECTION 6.0

Presentation of Results

The results for a given year of meteorology, each emission control scenario, and each Class I area will be presented as the maximum Δdv and 98th percentile Δdv over the 3-year period, as well as the maximum number of days per year that the maximum Δdv exceeds 0.5 dv.

For the BART analysis, the model results for each emission control scenario will be compared to those for the baseline scenario. Incremental differences between increasing levels of control will also be evaluated.

The methodology and results of the CALPUFF modeling analyses will be presented in a technical report for each unit that is subject to BART. Input and output files for the CALMET/CALPUFF modeling and post-processing will be provided in electronic format to the ADEQ. Larger files such as binary files generated by CALMET will not be included on the submitted disks, but any omitted files will be provided electronically upon request.

SECTION 7.0

References

Western Regional Air Partnership (WRAP) 2006. Draft Final Modeling Protocol, CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States. Western Regional Air Partnership, Air Quality Modeling Forum, Regional Modeling Center, August 15, 2006.

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Arizona BART Modeling Protocol and CALMET Settings by WRAP

TO: Arizona Electric Power Cooperative, Inc.

FROM: John Frohning/ CH2M HILL
Gordon Frisbie/ CH2M HILL
Mary Beth Yansura/ CH2M HILL

DATE: August 28, 2007

Introduction

CH2M HILL has evaluated the current Western Regional Air Partnership (WRAP) Best Available Retrofit Technology (BART) applicability assessments for facilities in Arizona. In their BART modeling, WRAP used the CALPUFF modeling system to estimate eligible facilities' impacts on federal CLASS I areas within 300-km of each facility.

Prior to conducting the modeling analysis, WRAP prepared a modeling protocol[1] which outlines their approach and selection of control parameter values (settings) used in the CALMET and CALPUFF control files. The WRAP protocol gives a fairly good support for their selection of several settings. However, some of the selected settings are not supported with any documentation including some of the CALMET settings used in the generation of the three-dimensional wind field.

Influence of Surface Meteorological Data

MM5 gridded three-dimensional meteorological data are used as the initial guess wind field in CALMET for both the WRAP and the proposed CH2M HILL analyses. These data can be further adjusted by introducing observational meteorological data and specifying the radius of influence of this data within or near the CALMET domain. The extent of this influence is established by the following parameters.

- IEXTRP – Extrapolation of surface wind observations to upper layers
- R1 - Relative weighting of the first guess field and observations in the surface layer
- RMAX1 - Maximum radius of influence over land in the surface layer
- R2 - Relative weighting of the first guess field and observations in the layers aloft
- RMAX2 - Maximum radius of influence over land aloft

R1 and R2 values describe the distance from the observed meteorological data station at which the surface data and initial guess wind field (MM5 data as adjusted for terrain and other effects) are weighted equally (i.e., the point at which the surface station is weighted

[1] *CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States.* August 2006

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50% and the initial guess wind field is weighted 50%). After the R1 and R2 distances, the initial guess wind field has more weight in the calculation of the CALMET wind field.

Generally, the R1 and R2 values are set to less than the RMAX1 and RMAX2 values to allow better smoothing between the observational data and the initial guess wind field.

Comparison of WRAP Settings and Proposed Settings

The R1, R2, RMAX1, and RMAX2 values selected by WRAP are not explained in the modeling protocol. The WRAP selected values for IEXTRP, R1, R2, RMAX1, and RMAX2 are summarized below:

- IEXTRP = 1 (no extrapolation of surface observation data is done)
- R1 = 100 km
- R2 = 200 km
- RMAX1 = 50 km
- RMAX2 = 100 km

WRAP has R1 and R2 values that are larger than the RMAX1 and RMAX2 values. This means at the RMAX distances, the surface stations are weighted *greater* than the MM5 data. Defining the parameters in this way causes a noticeable boundary in the wind field at the RMAX distances. This effect is known as *crop circling* in the wind field because there is a well defined circle around the meteorological data station in the processed wind vector map, where there is a discrepancy between the surface station data and the MM5 data (see Figure 1 for selected day in the WRAP-defined wind field).

Crop circles in the wind field may result in inaccurate results from the CALPUFF modeling because the wind field may be either shifting the plume transport too greatly between individual time steps, or may push the plume back to the original cell in a small time step.

To alleviate this problem, it is proposed that the R1, R2, RMAX1, and RMAX2 values be modified to allow better smoothing in the wind field.

In addition, by using an IEXTRP value of 1, the WRAP CALMET processing prevents the surface stations from influencing the meteorological data above the surface layer (see Figure 2 for selected day at WRAP-defined IEXTRP value of 1). We are proposing to use an IEXTRP value of 4 (the CALMET default value) which allows some influence of the surface data on the layers above the surface.

After evaluating the locations of the meteorological stations and the proximity of the stations to each other and nearby terrain features, the proposed R1, R2, RMAX1, and RMAX2 values are summarized below.

- IEXTRP = 4 (similarity theory used)
- R1: 25-km
- R2: 25-km
- RMAX1: 50-km
- RMAX2: 50-km

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Changing the IEXTRP, R1, R2, RMAX1, and RMAX2 to the values above results in better smoothing in the CALMET wind field at the RMAX distances and minimizes the crop circling affect surrounding each surface station. This also allows a reasonable amount of surface station influence on the upper layers of meteorological data. Figures 3 and 4 present the resulting proposed wind fields that can be compared to the WRAP wind fields (Figures 1 and 2).

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Figure 1 – WRAP Wind Field, Surface Layer, Date: 12/08/2001, Hour: 02

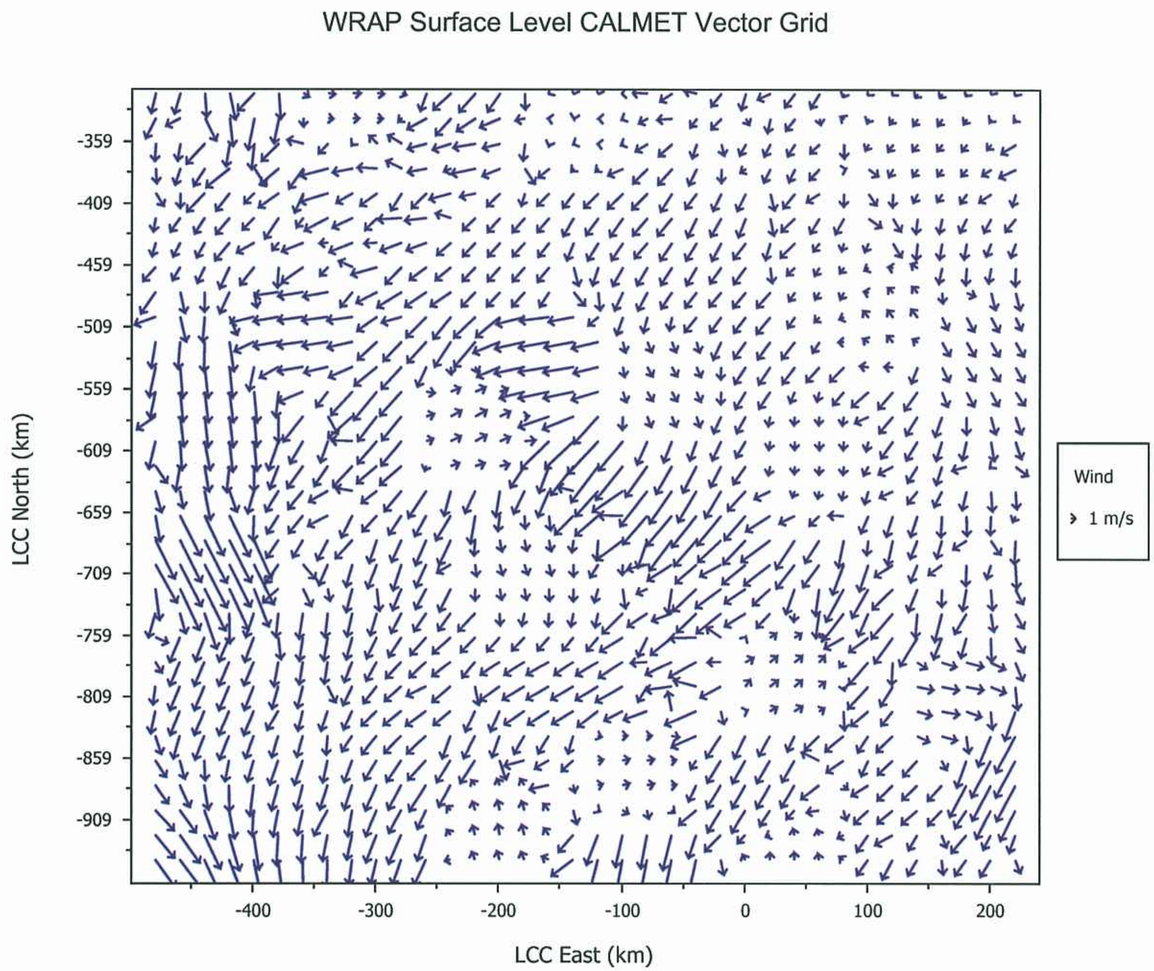

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Figure 2 – WRAP Wind Field, Layer 2, Date: 12/08/2001, Hour: 02

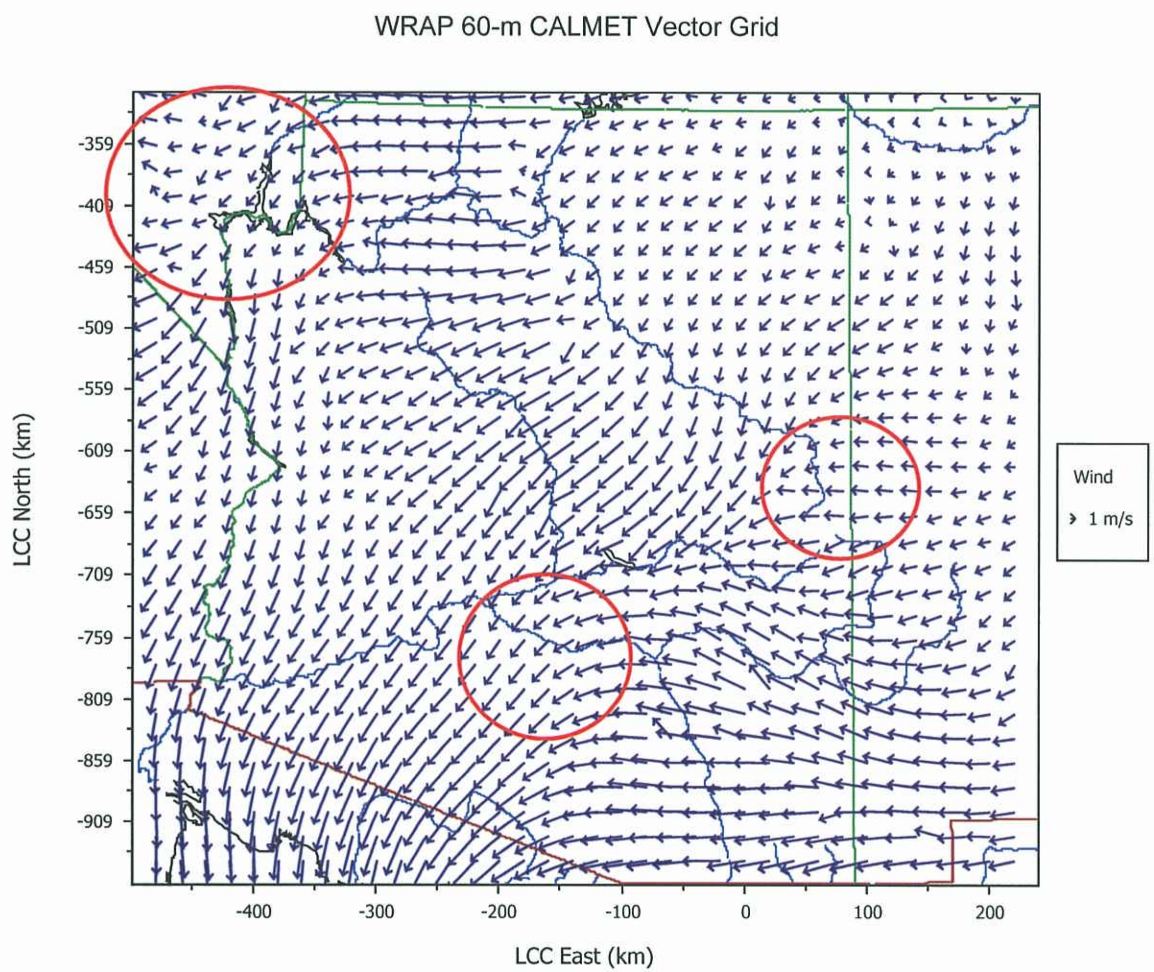

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Figure 3 – Proposed Revised Wind Field, Surface Layer, Date: 12/08/2001, Hour: 02

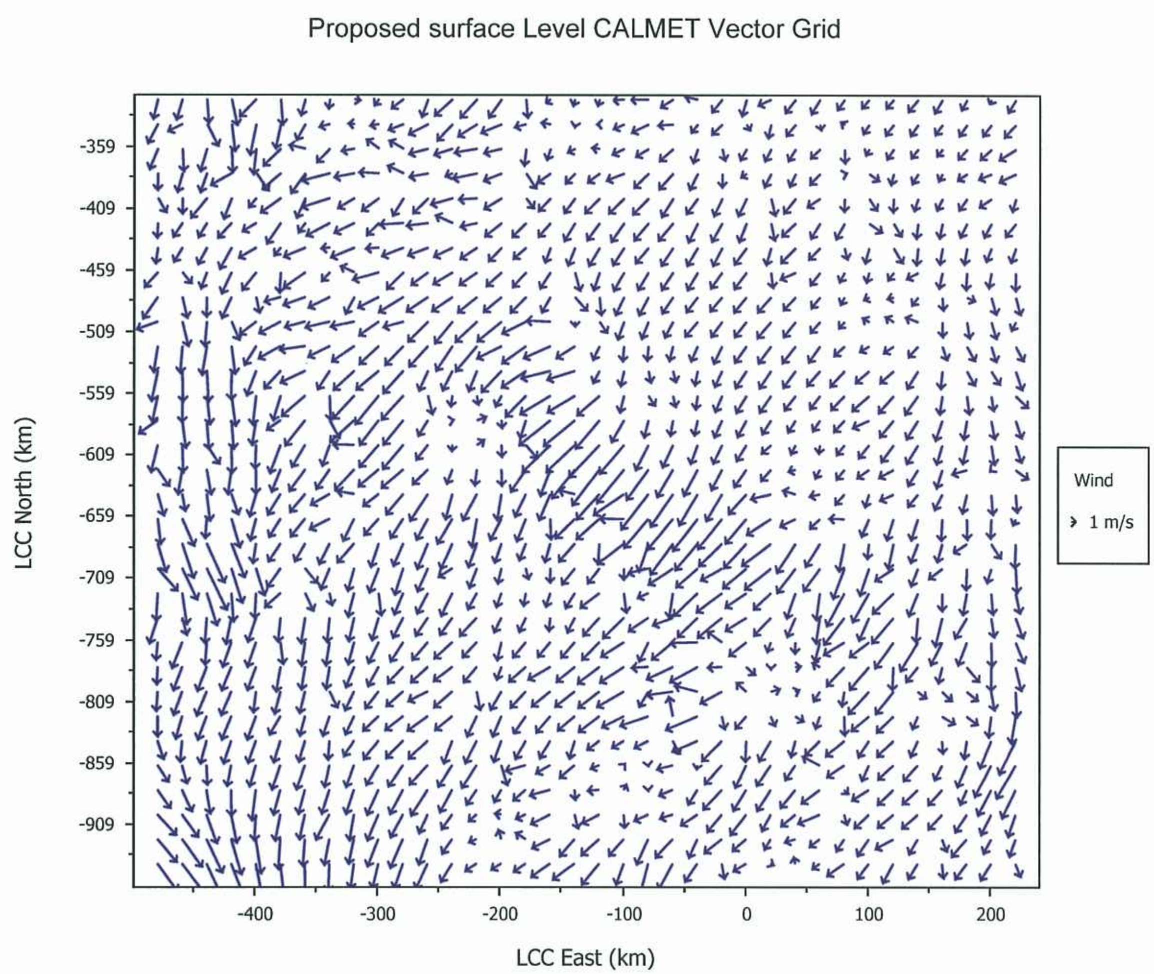

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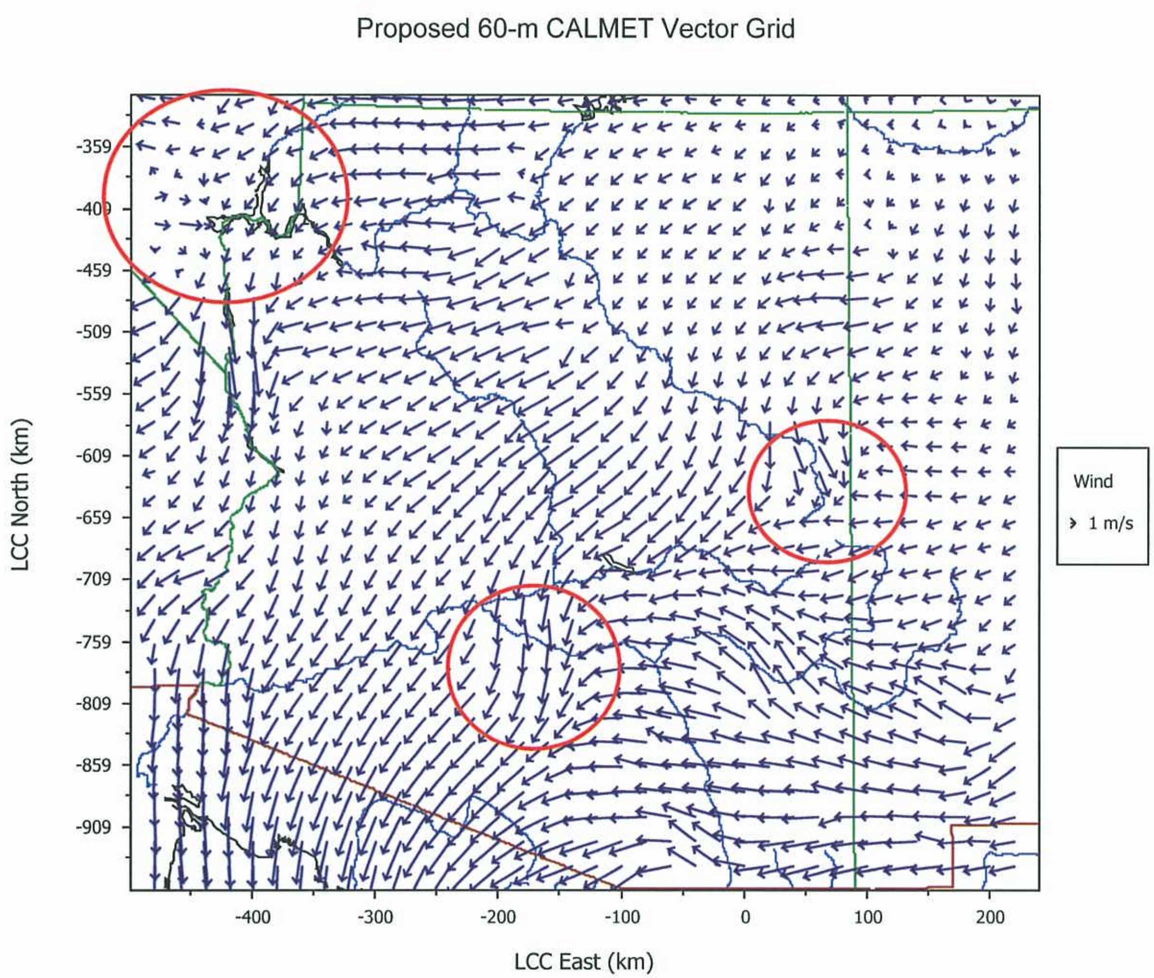
Figure 4 – Proposed Revised Wind Field, Layer 2, Date: 12/08/2001, Hour: 02



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From: Eric C. Massey <Massey.Eric@azdeq.gov>
To: mfreeark@ssw.coop <mfreeark@ssw.coop>
Cc: Leonard H. Montenegro <Montenegro.Leonard@azdeq.gov>; Jie Yang <Yang.Jie@azdeq.gov>; Trevor Baggiore <Baggiore.Trevor@azdeq.gov>; jandrew@aepco.coop <jandrew@aepco.coop>; Montalvo, Kara/PHX
Sent: Fri Sep 28 10:54:01 2007
Subject: RE: AEPCO Modeling Protocol Amendment

Michelle,

Thank you for the follow-up call yesterday, as well as your e-mail. I've looked through my records, and I can't find any evidence that I responded to the September 7, 2007, e-mail. Please accept my sincere apologies. It seems that I had all of the information to respond, and I thought I had responded, but perhaps I am remembering my intention to respond. In either event, I apologize for the delay in responding. Here is ADEQ's response to AEPCO's request that we reconsider some of our previous decisions:

ADEQ has reevaluated AEPCO's proposal of using IEXTRP=4 in their CALPUFF modeling for BART analysis. This option allows CALMET to extrapolate surface observational wind to upper level. ADEQ agrees that this option will allow a fully use of the on-site meteorological data. ADEQ approves the use of IEXTRP=4 for AEPCO's BART modeling. Considering the CALMET model only extrapolating surface wind up to the user specified minimum mixing height (ZIMIN) (Version 6), ADEQ requires that ZIMIN be set as the same value that WRAP used in their BART screening modeling, i.e. 50 meters. This setting will eliminate surface extrapolation at layers that are more than 50 meters above the ground. This is appropriate since the upper layer wind should be free of surface terrain impact and is most likely to be different from the surface wind.

ADEQ also approves the use of default BIAS values, i.e. zero for all vertical layers. Since there will be no upper air observational data to be processed in CALMET, the actual value of BIAS should have no impact on model behavior.

Finally, to confirm our discussion yesterday, I had spoken with the Regional Modeling Center, and they indicated that they would not be able to re-run the original modeling analysis for us. My recommendation would be to work with your consultant to run two versions of your model. One with the correct coal data, before applying any potential BART controls, and the second with the correct coal data along with the BART controls. When submitting this analysis to us, please just remind us that the original modeling anlaysis used an incorrect set of emissions factors, and that you re-ran the model to provide us with more representative information about the source's pre-BART impacts.

Thanks for the reminders, and I am terribly sorry that this did not get communicated to you sooner.

Eric

To: "Eric C. Massey" <Massey.Eric@azdeq.gov>
From: James Andrew/Power Production/SSW
Date: 09/07/2007 09:59AM
cc: Kara.Montalvo@ch2m.com, "Eric C. Massey" <Massey.Eric@azdeq.gov>, mfreeark@ssw.coop, "Leonard H. Montenegro" <Montenegro.Leonard@azdeq.gov>, "Jie Yang" <Yang.Jie@azdeq.gov>
Subject: RE: AEPCO Modeling Protocol Amendment

Eric,

AEPCO respectfully submits this response to ADEQ's comments on the BART Modeling Protocol Amendment.

We realize that ADEQ has stated that it cannot support the default CALMET setting of IEXTRP = 4 but AEPCO urges ADEQ to reconsider. Applying the default CALMET setting of IEXTRP = 4, as proposed by CH2MHILL, will allow AEPCO to more fully utilize actual on-site hourly meteorological data for Apache Generating Station to achieve the goal of CALMET/CALPUFF modeling - to generate spatially and temporally refined estimates of pollutant dispersion.

In CALMET, MM5 data are used as the "first guess" wind fields. Geographically, the MM5 data only have a 36-kilometer resolution, and the smallest MM5 time interval is set by surface data which "nudges" the estimates at 3-hour intervals. CALPUFF modeling estimates dispersion at 1-hour intervals, and allows the pollutant dispersion to be estimated over a finer horizontal grid resolution.

Using MM5 to generate CALPUFF results could miss many wind events and wind shifts in the upper air that may exist at finer spatial and temporal resolution. This could be especially important for locations with on-site hourly meteorological data, or within areas with higher resolution terrain influence. Extrapolating the surface observations takes advantage of finer resolution data to determine the initial direction that the plume is traveling in the layers aloft. Note that this influence is regulated by using the Similarity Theory in Version 6 of CALMET, which uses Beljaars and Holtslag (1991) as opposed to van Ulden and Holtslag (1985) to correct some errors with interpolation above 200 meters.

WRAP has stated that there is a conflict between IEXTRP = 4 and RMIN2 = 4. RMIN2 is the distance surrounding an upper air station where surface data will not be used to extrapolate to upper layers. Since no upper air observation station data were used in developing the grid, this is a moot point. The false velocities WRAP is referencing would occur at the boundary of the 4-km radius around upper air stations that don't exist.

Additionally, setting BIAS to 0 does not create an unlimited influence of extrapolated surface wind in the upper layers. The BIAS value changes the weighting of the upper air station or surface station data based on vertical extrapolation. Changing this setting would be negligible in this case since there is no upper air data to weigh against in the wind field. The only change that would make a difference would be to completely eliminate the surface data influence for certain levels. However, since IEXTRP = 4, Similarity Theory is used so the surface station already has less influence on the higher vertical levels.

In summary, surface data provide actual meteorological conditions that are averaged at 1-hour intervals. These data capture real meteorological conditions that may not be accounted for in the coarse resolution of the MM5 data. Limiting the effects of these data to the 10 meter level, would neglect the actual dispersion of air pollutants above this level that would occur at these times. It would be more realistic to allow limited influence of the surface data in the levels above the 10 meter layer. These effects would be vertically limited by Similarity Theory, and horizontally by the R and RMAX values.

Thank you for your consideration.

James M. Andrew
Manager of Regulatory Affairs
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Appendix C
Additional BART Modeling Results

APPENDIX C

Additional BART Modeling Results

FIGURE C-1
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Gila Wilderness
Apache 1

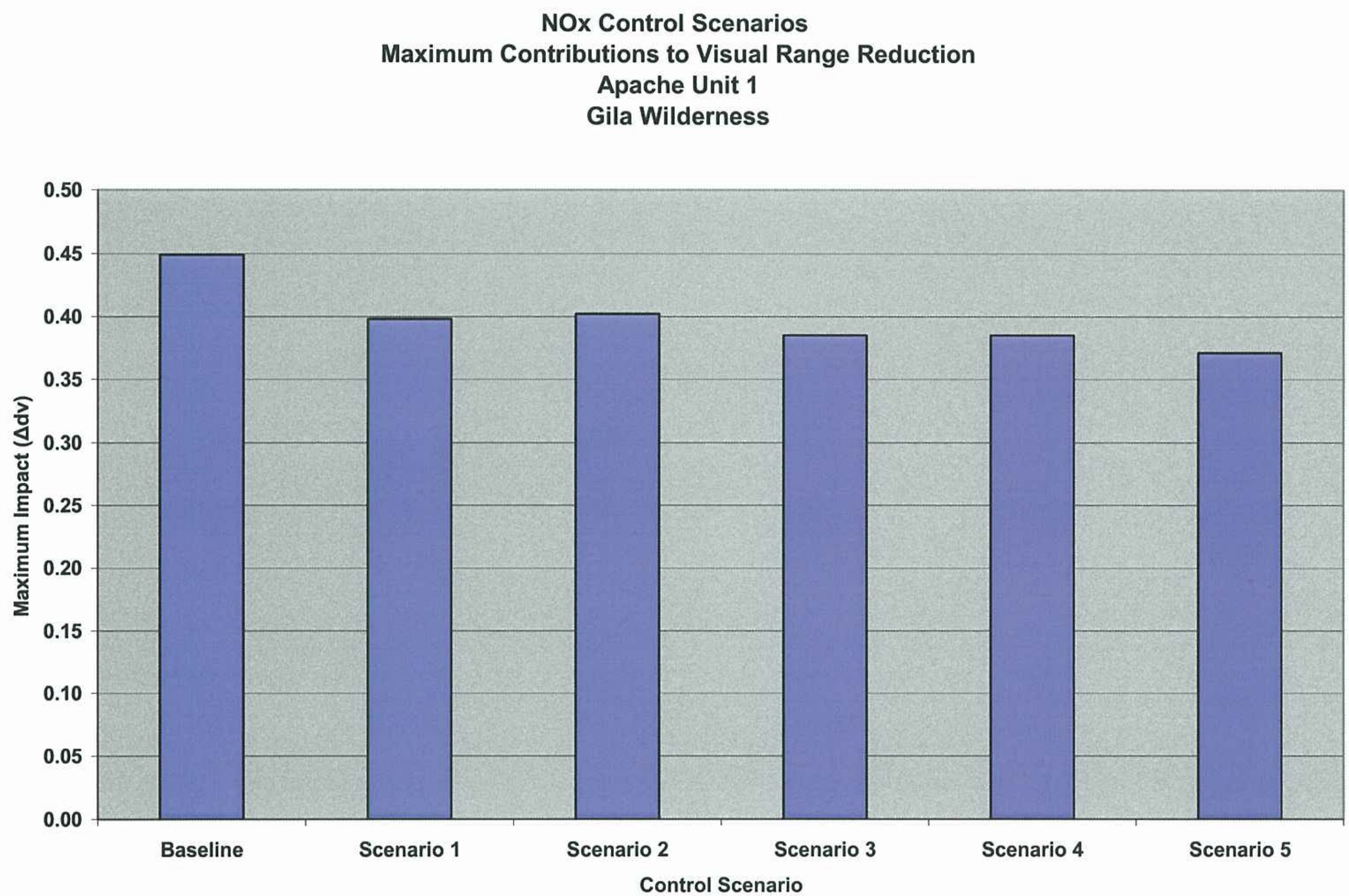

FIGURE C-2
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Mount Baldy Wilderness
Apache 1

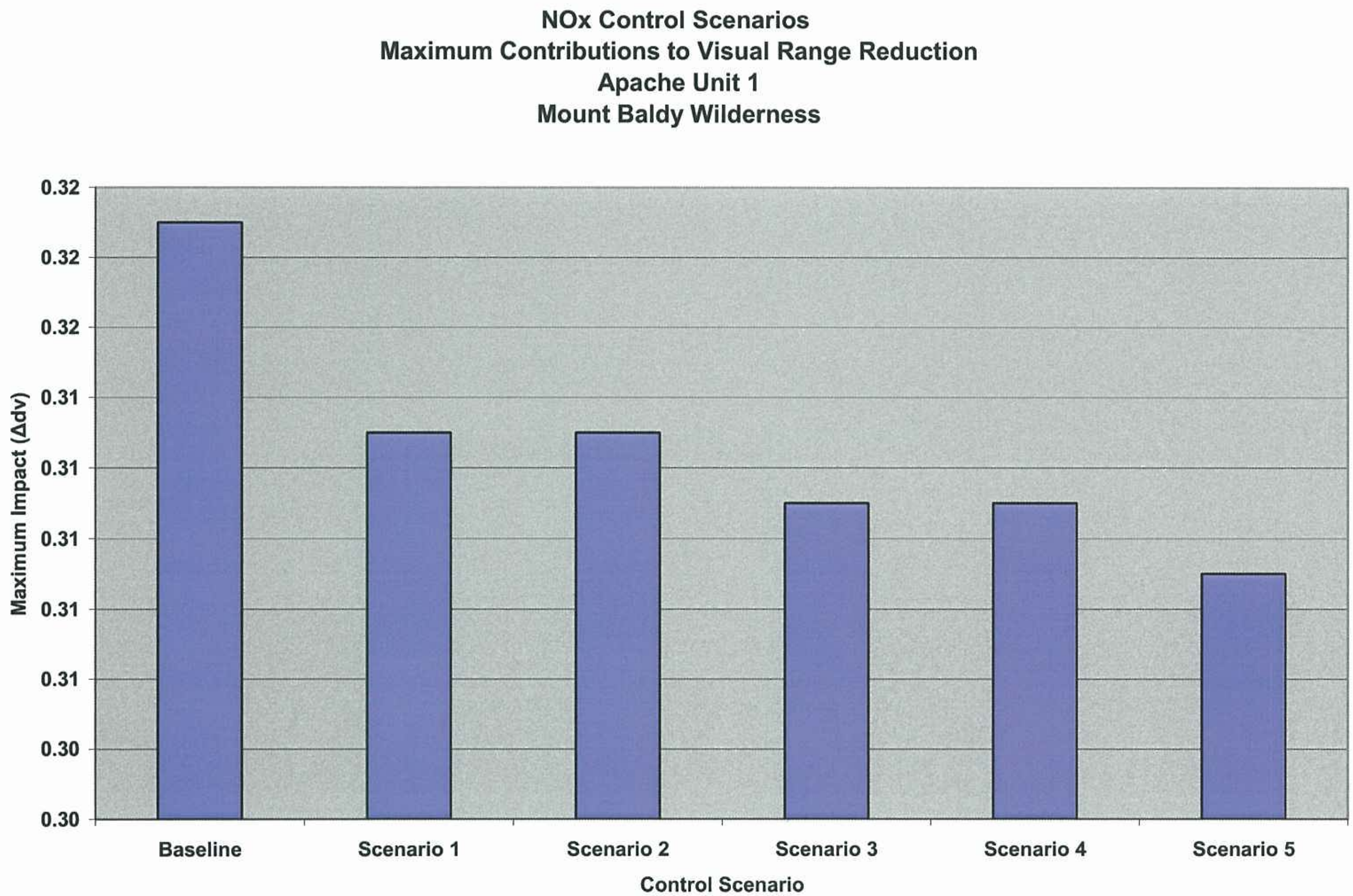

FIGURE C-3
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Sierra Ancha Wilderness
Apache 1

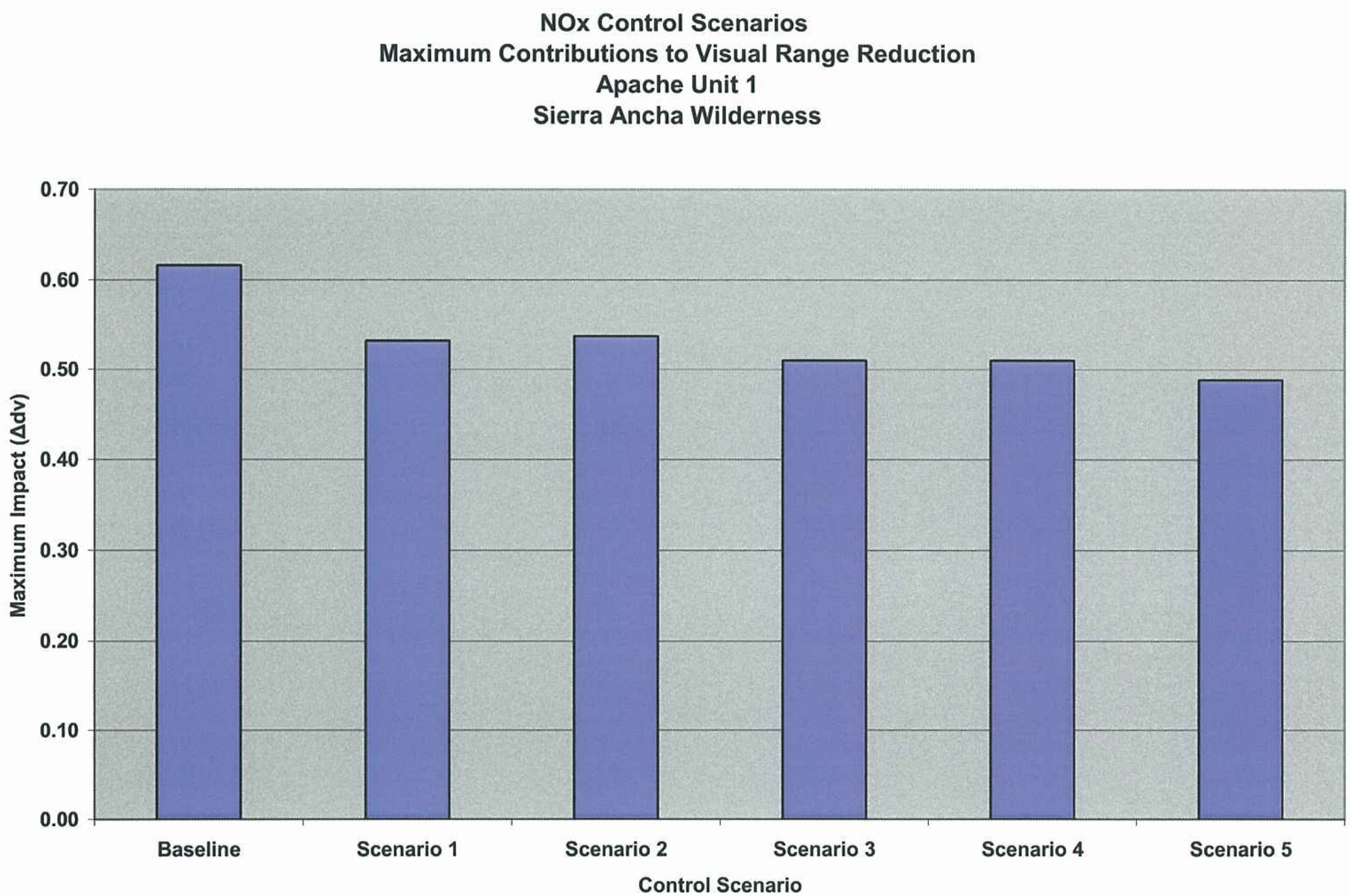

FIGURE C-4
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Mazatzal Wilderness
Apache 1

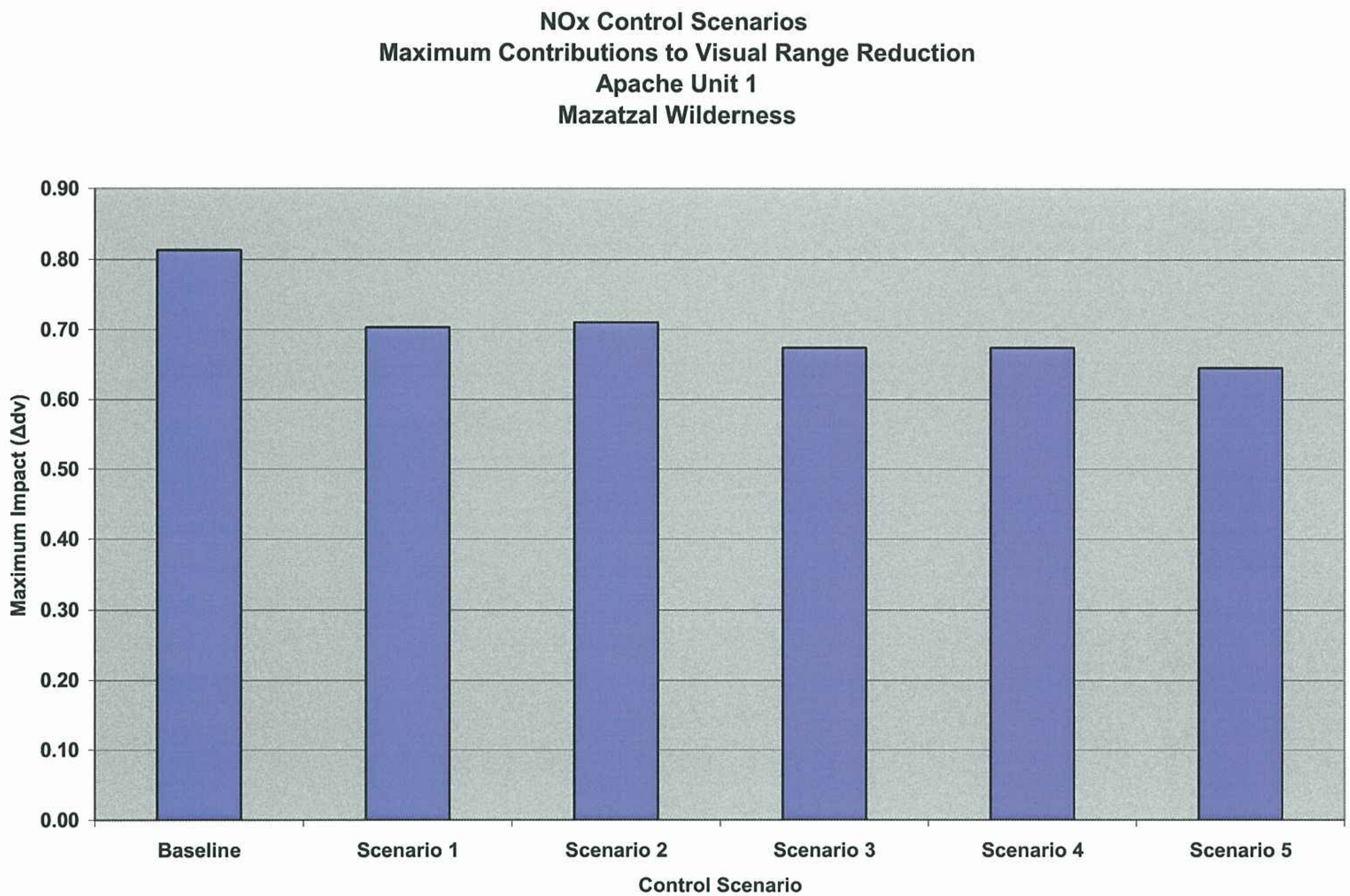

FIGURE C-5
NO_x Control Scenarios - Maximum Contributions to Visual Range Reduction at Pine Mountain Wilderness
Apache 1

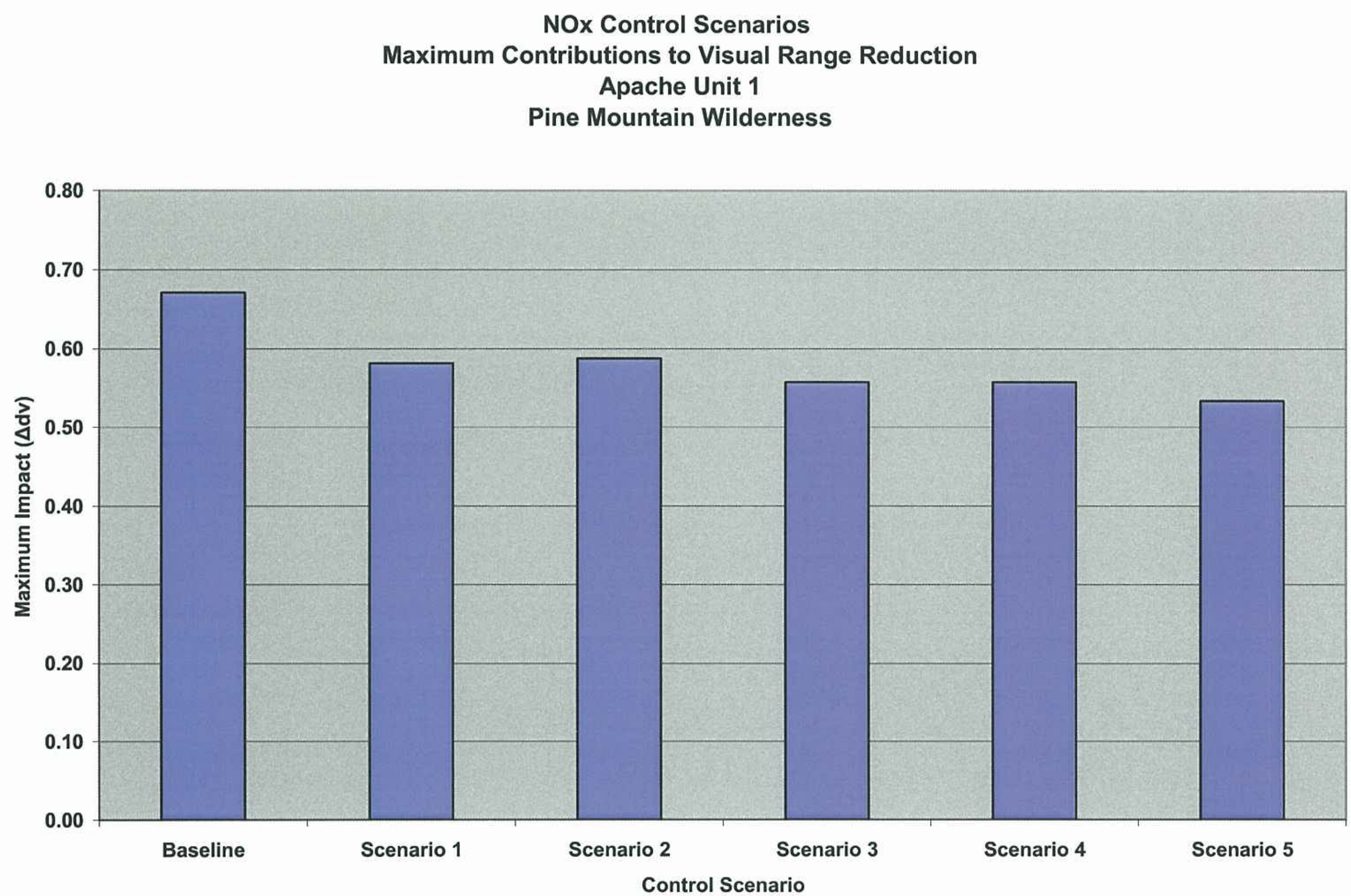

TABLE C-1
NO_x Control Scenario Results for Gila Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		0	0.000	0.000	0.000	0.000
1	LNB w/FGR	0	0.020	0.552	NA	27.599
2	ROFA	0	0.048	0.939	NA	19.564
3	ROFA w/Rotamix	0	0.030	1.506	NA	50.194
4	LNB w/ FGD & SNCR	0	0.030	1.079	NA	35.980
5	SCR	0	0.061	5.705	NA	93.521

TABLE C-2
NO_x Control Scenario Results for Mount Baldy Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		0	0.000	0.000	0.000	0.000
1	LNB w/FGR	0	0.008	0.552	NA	68.998
2	ROFA	0	0.013	0.939	NA	72.238
3	ROFA w/Rotamix	0	0.010	1.506	NA	150.583
4	LNB w/ FGD & SNCR	0	0.010	1.079	NA	107.939
5	SCR	0	0.021	5.705	NA	271.657

TABLE C-3
NO_x Control Scenario Results for Sierra Ancha Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0.000	0.000	0.000	0.000
1	LNB w/FGR	2	0.021	0.552	NA	26.285
2	ROFA	2	0.033	0.939	NA	28.457
3	ROFA w/Rotamix	1	0.026	1.506	1.506	57.916
4	LNB w/ FGD & SNCR	1	0.026	1.079	1.079	41.515
5	SCR	0	0.044	5.705	2.852	129.655

TABLE C-4
NO_x Control Scenario Results for Mazatzal Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0.000	0.000	0.000	0.000
1	LNB w/FGR	2	0.007	0.552	NA	78.855
2	ROFA	2	0.038	0.939	NA	24.713
3	ROFA w/Rotamix	2	0.016	1.506	NA	94.114
4	LNB w/ FGD & SNCR	2	0.016	1.079	NA	67.462
5	SCR	2	0.039	5.705	NA	146.277

TABLE C-5
NO_x Control Scenario Results for Pine Mountain Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0.000	0.000	0.000	0.000
1	LNB w/FGR	2	0.015	0.552	NA	36.799
2	ROFA	2	0.029	0.939	NA	32.383
3	ROFA w/Rotamix	1	0.021	1.506	1.506	71.706
4	LNB w/ FGD & SNCR	1	0.021	1.079	1.079	51.399
5	SCR	1	0.040	5.705	5.705	142.620

TABLE C-6
Gila Wilderness NO_x Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	0	0.020	0.552	NA	27.599
Scenario 2 vs. Scenario 1	0	0.028	0.387	NA	13.825
Scenario 5 vs. Scenario 2	0	0.013	4.766	NA	366.593

TABLE C-7
Mount Baldy Wilderness NO_x Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	0	0.008	0.552	NA	68.998
Scenario 2 vs. Scenario 1	0	0.005	0.387	NA	77.422
Scenario 5 vs. Scenario 2	0	0.008	4.766	NA	595.713

TABLE C-8
Sierra Ancha Wilderness Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	0	0.021	0.552	NA	26.285
Scenario 2 vs. Scenario 1	0	0.012	0.387	NA	32.259
Scenario 5 vs. Scenario 2	2	0.011	4.766	2.383	433.246

TABLE C-9
Mazatzal Wilderness NO_x Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	0	0.007	0.552	NA	78.855
Scenario 2 vs. Scenario 1	0	0.031	0.387	NA	12.487
Scenario 5 vs. Scenario 2	0	0.001	4.766	NA	4765.767

TABLE C-10
Pine Mountain Wilderness NO_x Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 1 vs. Baseline	0	0.015	0.552	NA	36.799
Scenario 2 vs. Scenario 1	0	0.014	0.387	NA	27.651
Scenario 5 vs. Scenario 2	1	0.011	4.766	4.766	433.246

FIGURE C-6
NO_x Control Scenarios - Least Cost Envelope Gila Wilderness - Days Reduction
Apache 1

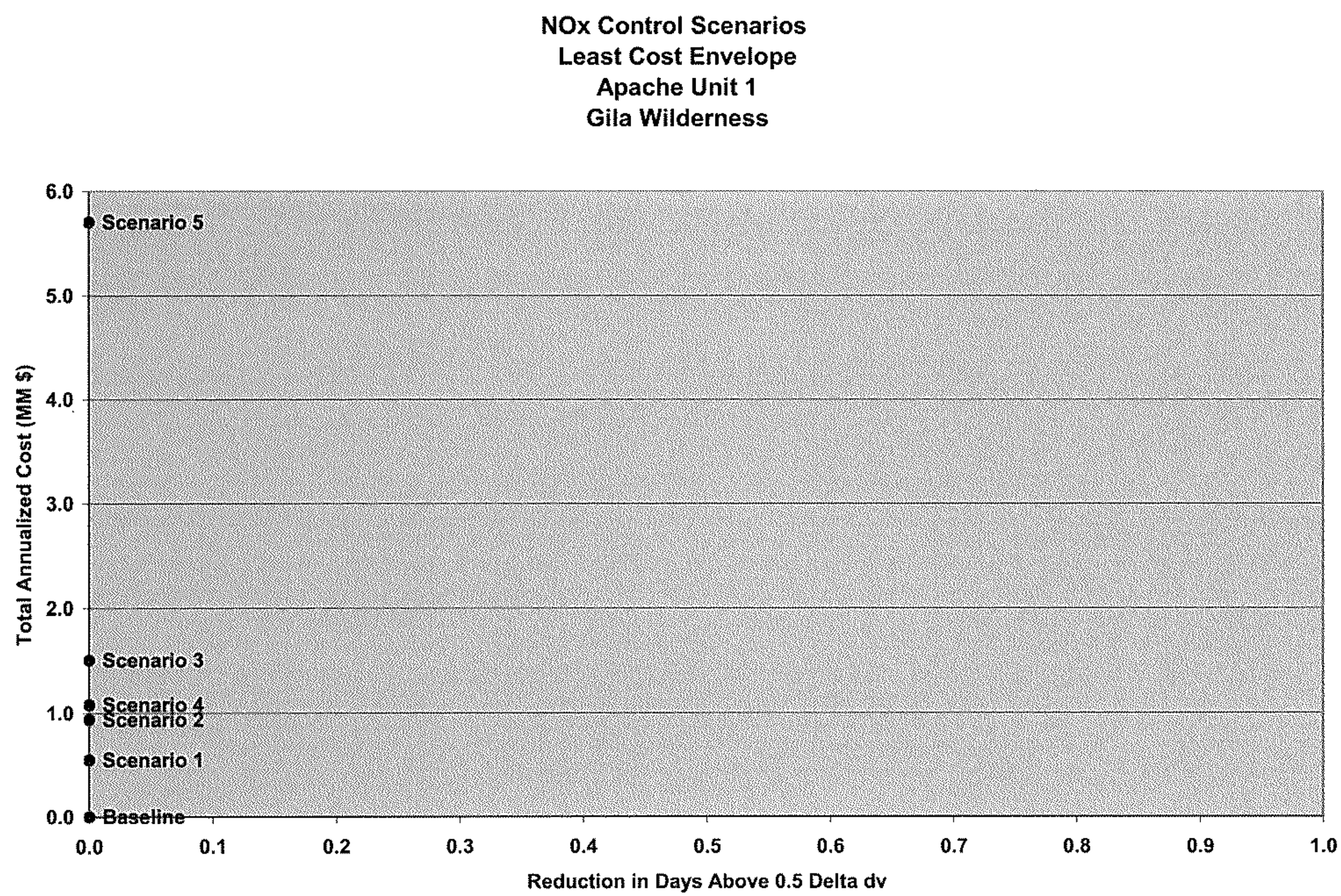

FIGURE C-7
NO_x Control Scenarios - Least Cost Envelope Gila Wilderness - 98th Percentile Reduction
Apache 1

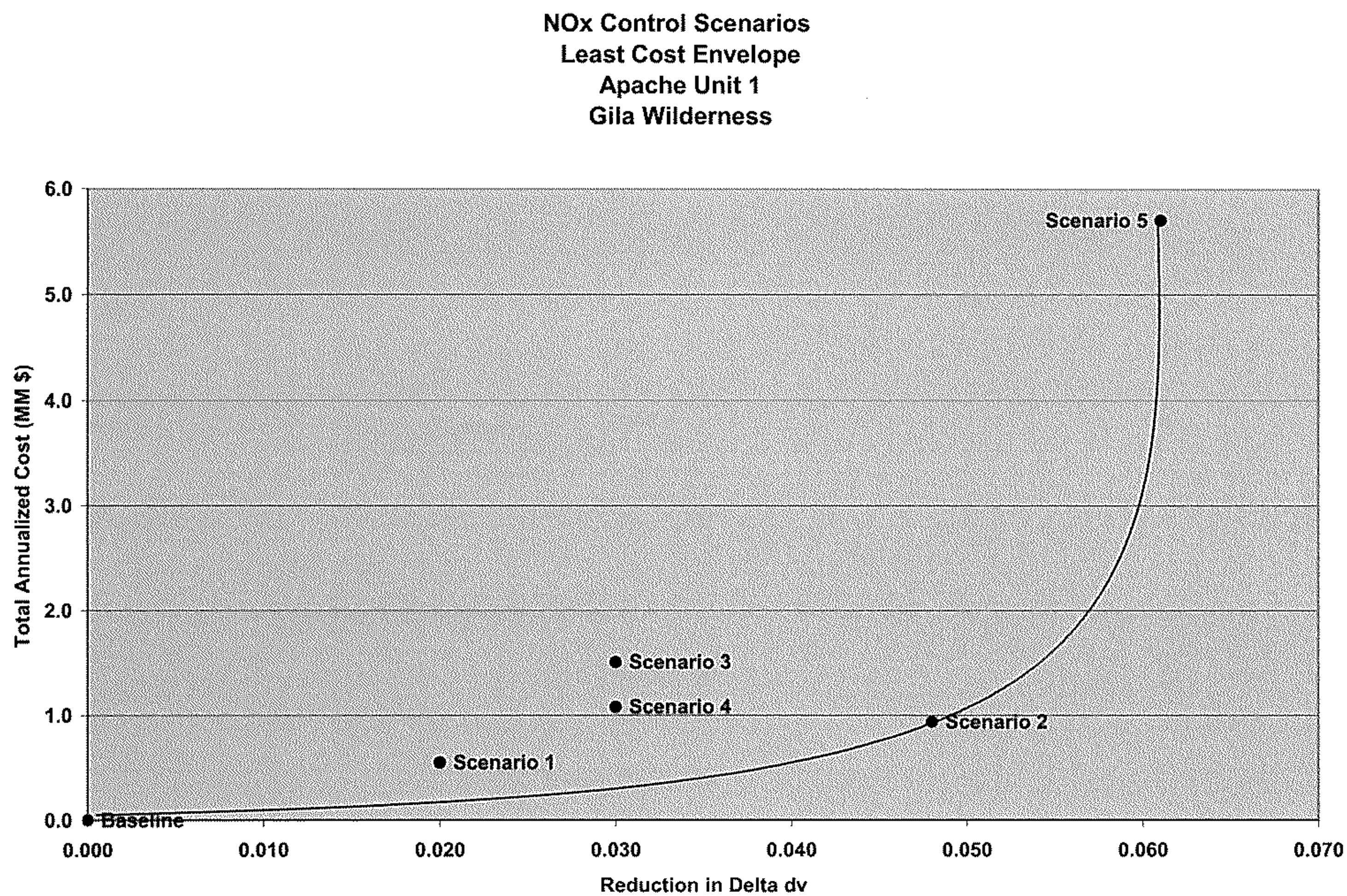

FIGURE C-8
NO_x Control Scenarios - Least Cost Envelope Mount Baldy Wilderness - Days Reduction
Apache 1

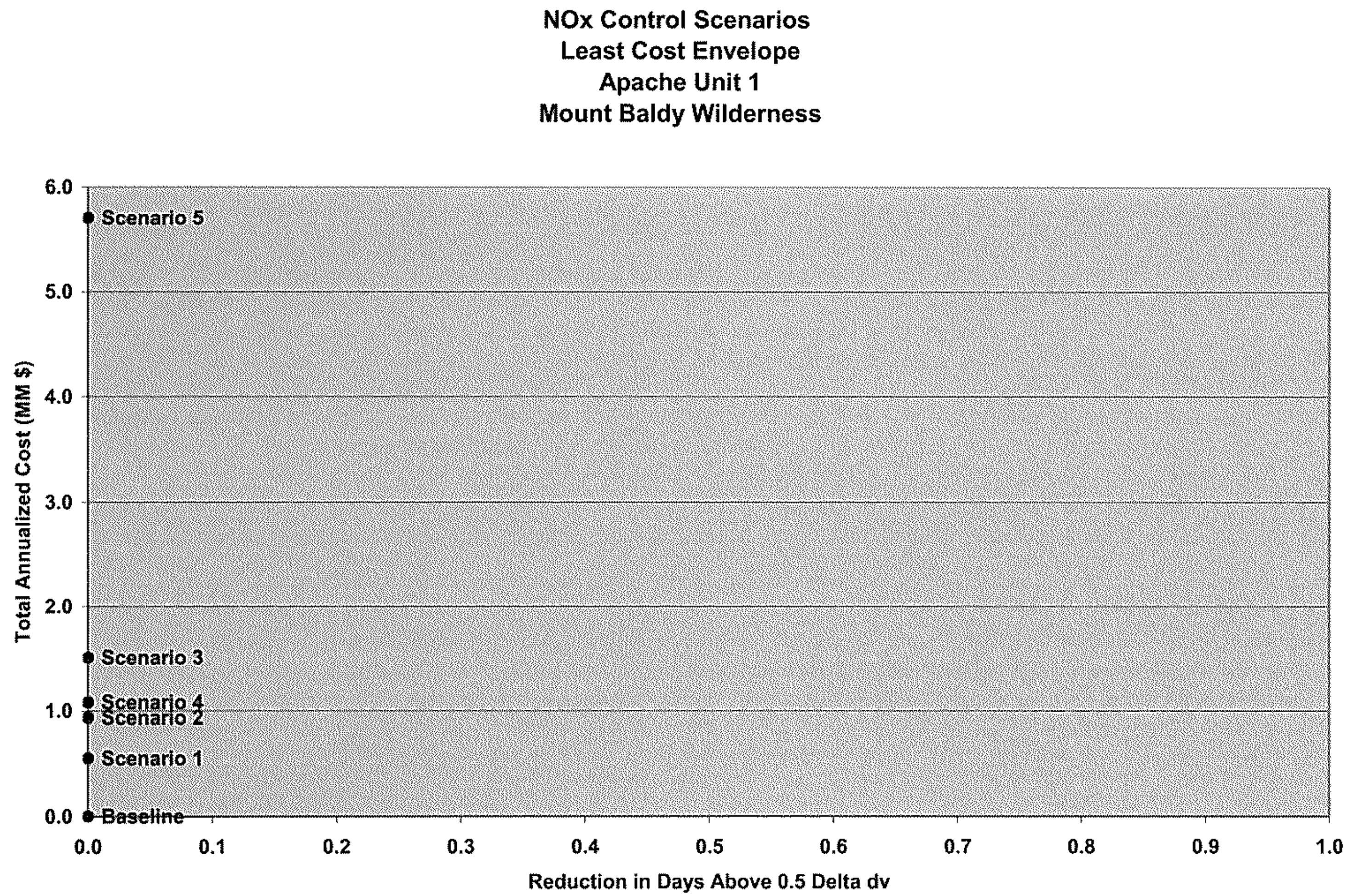

FIGURE C-9
NO_x Control Scenarios - Least Cost Envelope Mount Baldy Wilderness - 98th Percentile Reduction
Apache 1

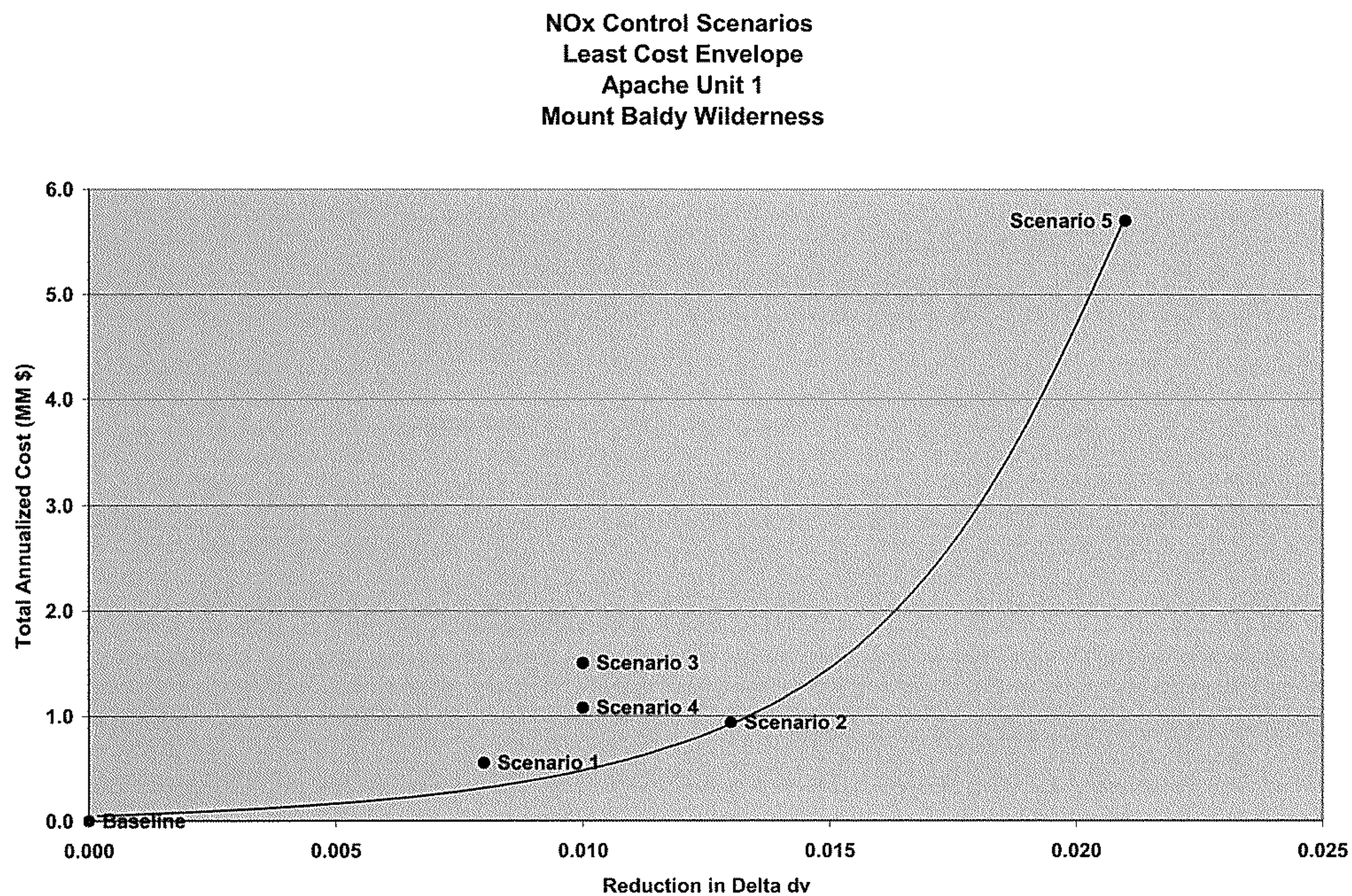

FIGURE C-10
NO_x Control Scenarios - Least Cost Envelope Sierra Ancha Wilderness - Days Reduction
Apache 1

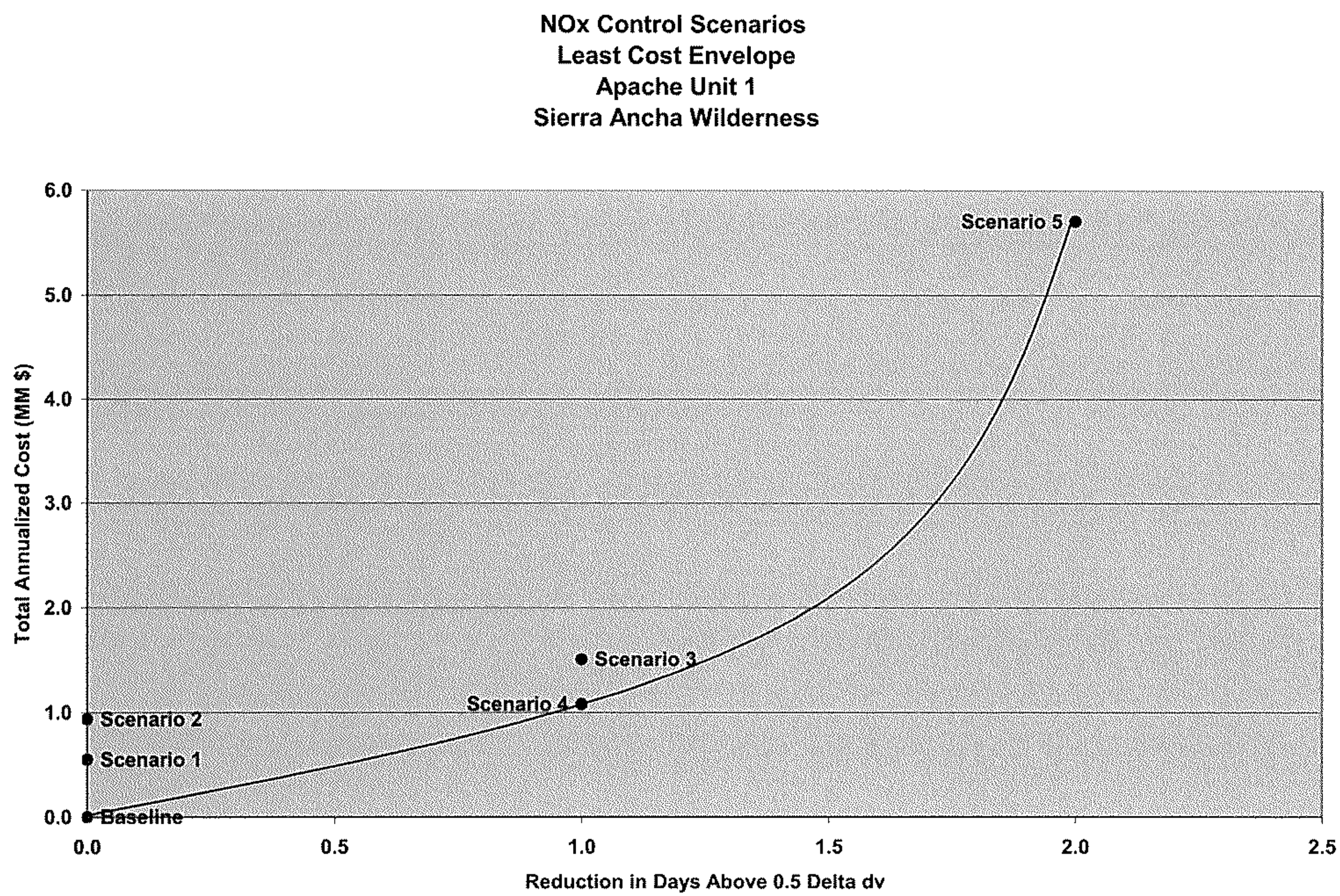

FIGURE C-11
NO_x Control Scenarios - Least Cost Envelope Sierra Ancha Wilderness - 98th Percentile Reduction
Apache 1

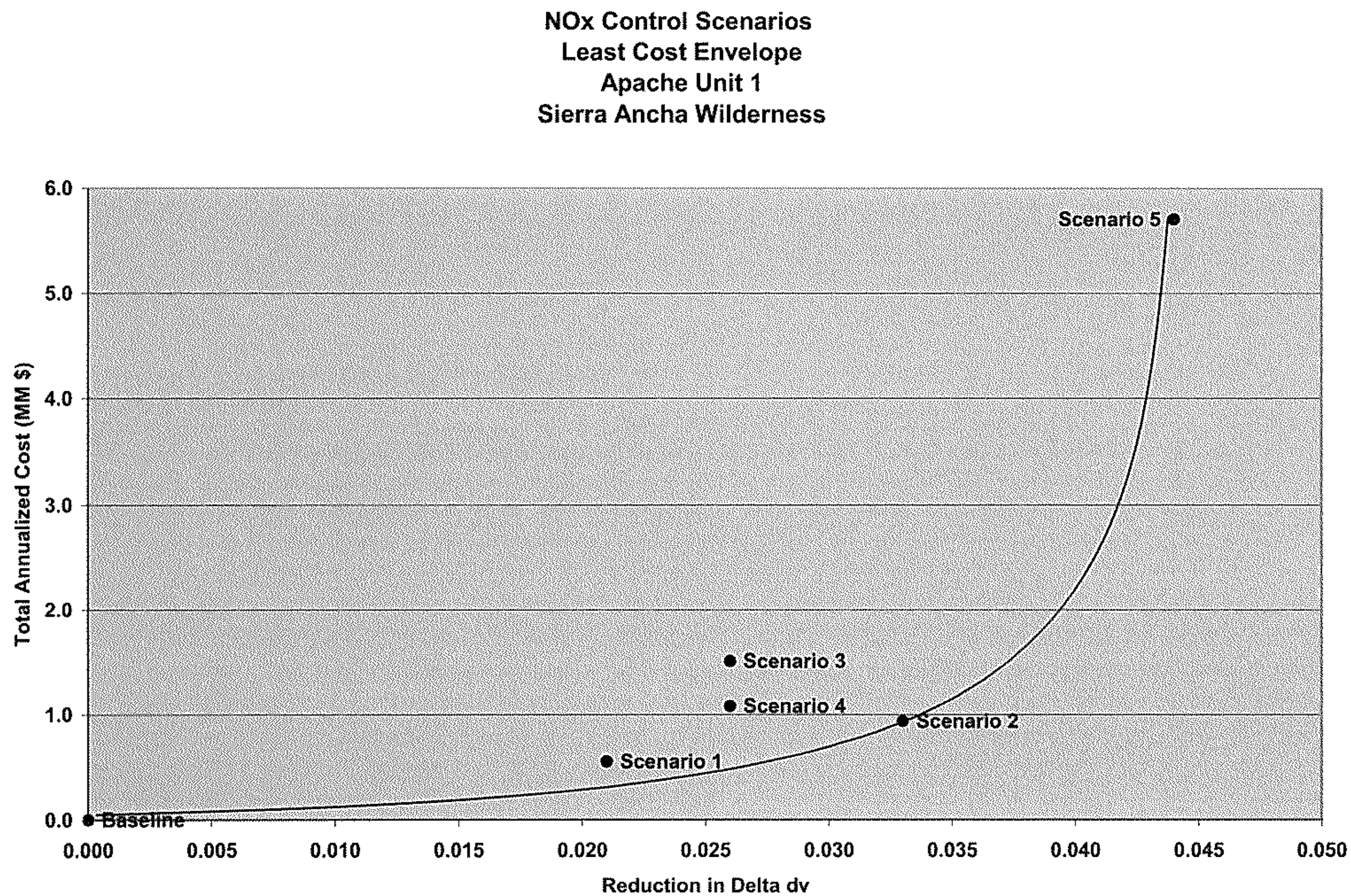

FIGURE C-12
NO_x Control Scenarios - Least Cost Envelope Mazatzal Wilderness - Days Reduction
Apache 1

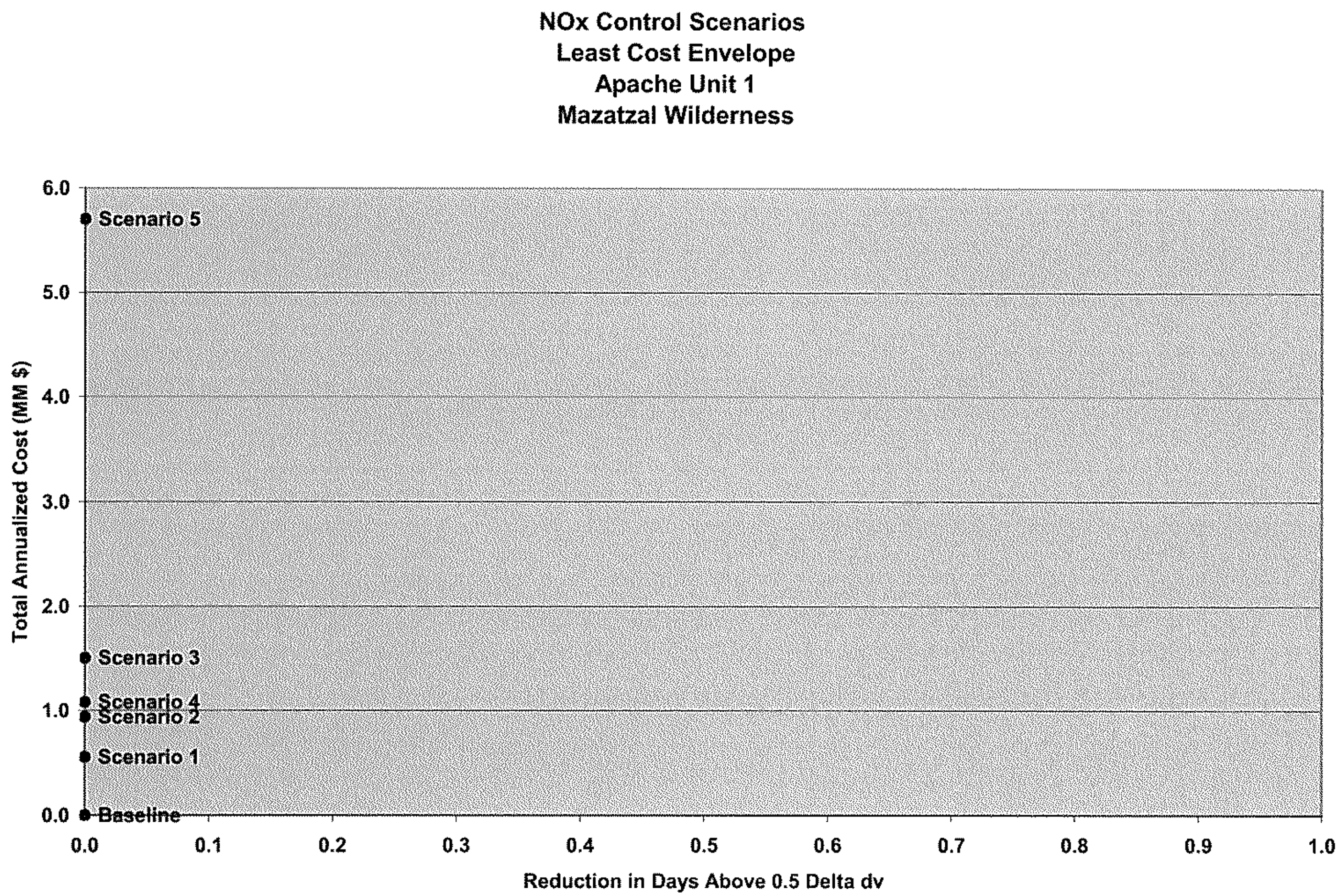

FIGURE C-13
NO_x Control Scenarios - Least Cost Envelope Mazatzal Wilderness - 98th Percentile Reduction
Apache 1

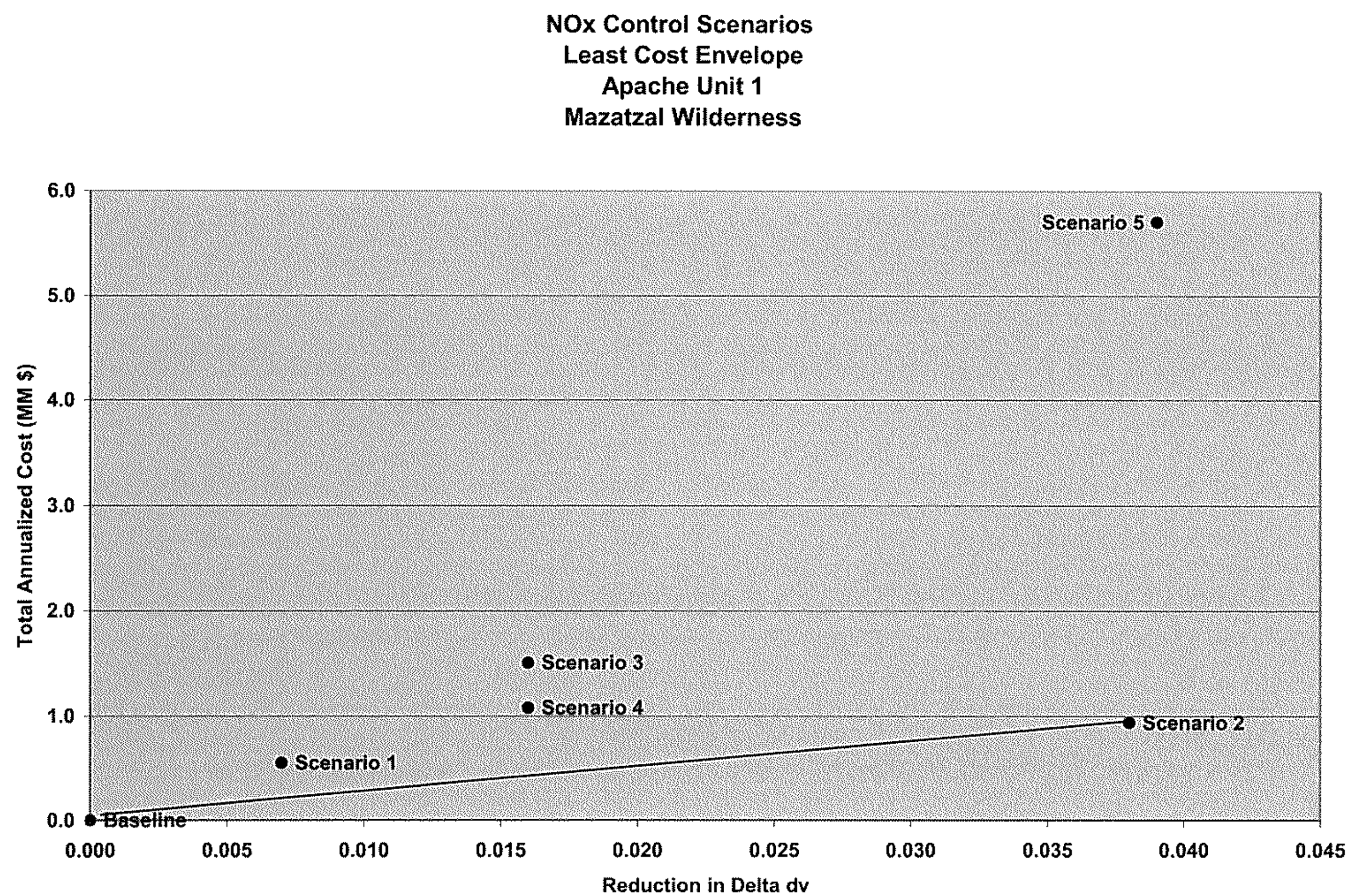

FIGURE C-14
NO_x Control Scenarios - Least Cost Envelope Pine Mountain Wilderness - Days Reduction
Apache 1

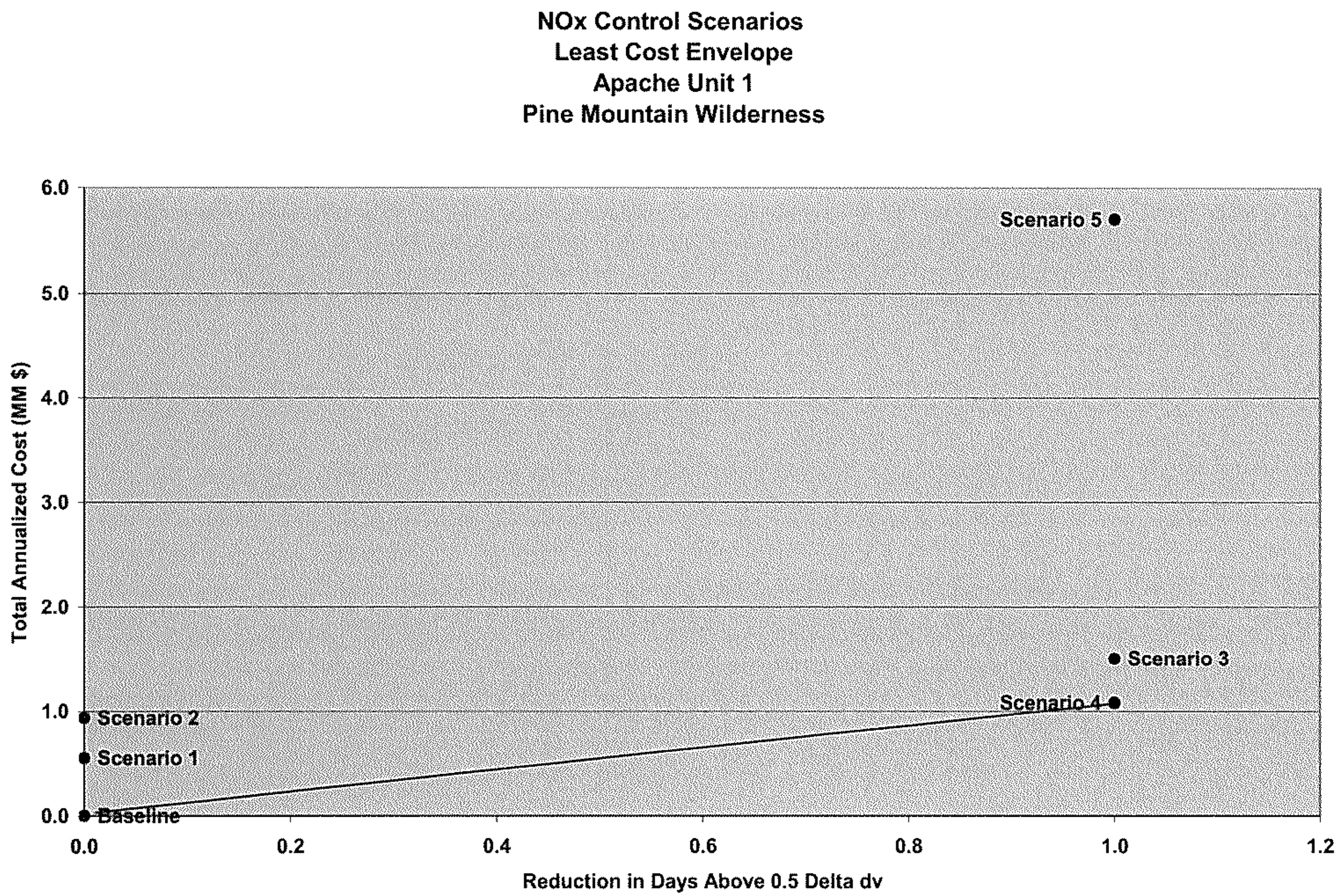

FIGURE C-15
NO_x Control Scenarios - Least Cost Envelope Pine Mountain Wilderness - 98th Percentile Reduction
Apache 1

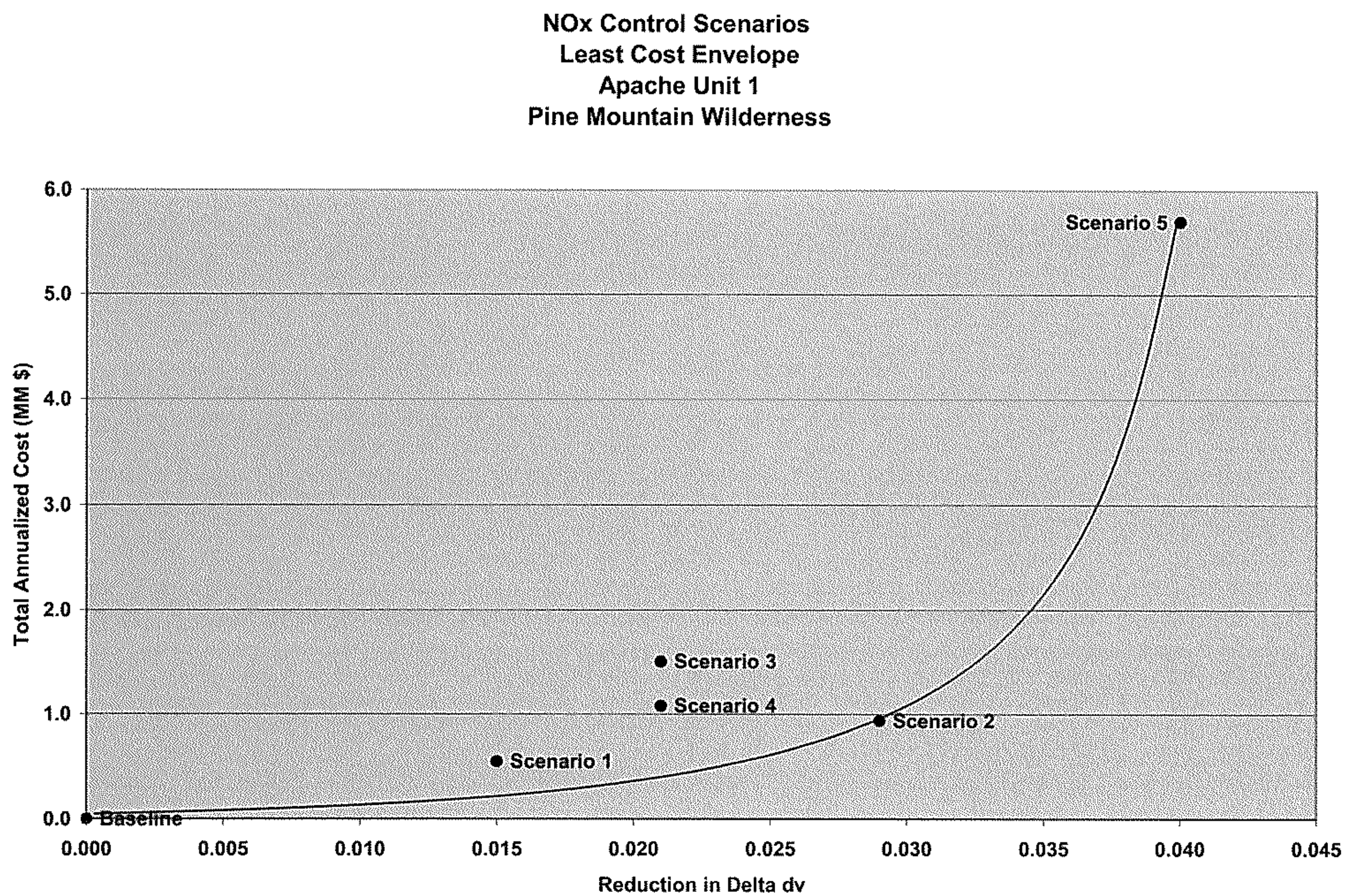

FIGURE C-16
PM & SO_2 Control Scenarios - Maximum Contributions to Visual Range Reduction at Gila Wilderness
Apache 1

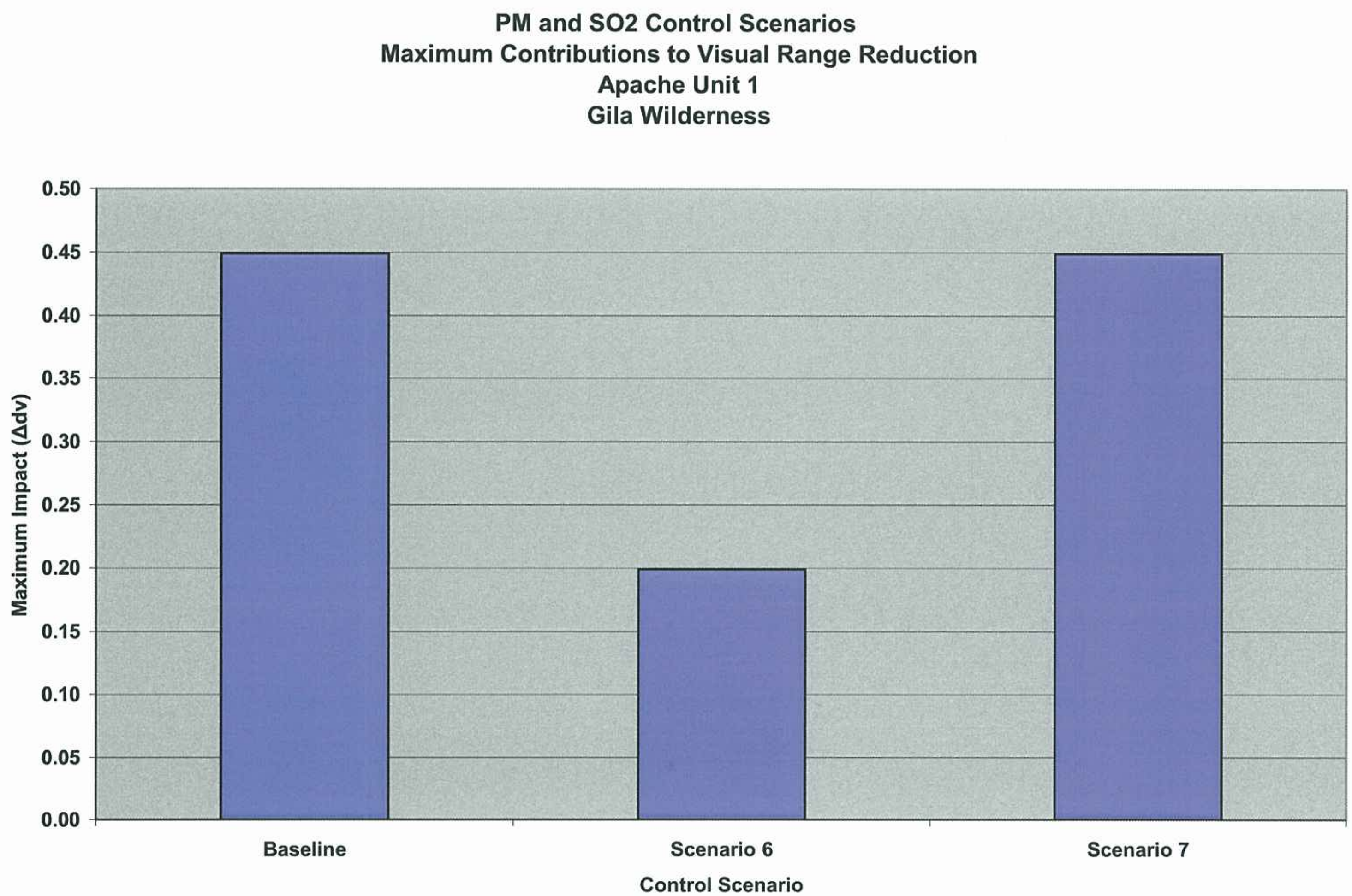

FIGURE C-17
PM & SO_2 Control Scenarios - Maximum Contributions to Visual Range Reduction at Mount Baldy Wilderness
Apache 1

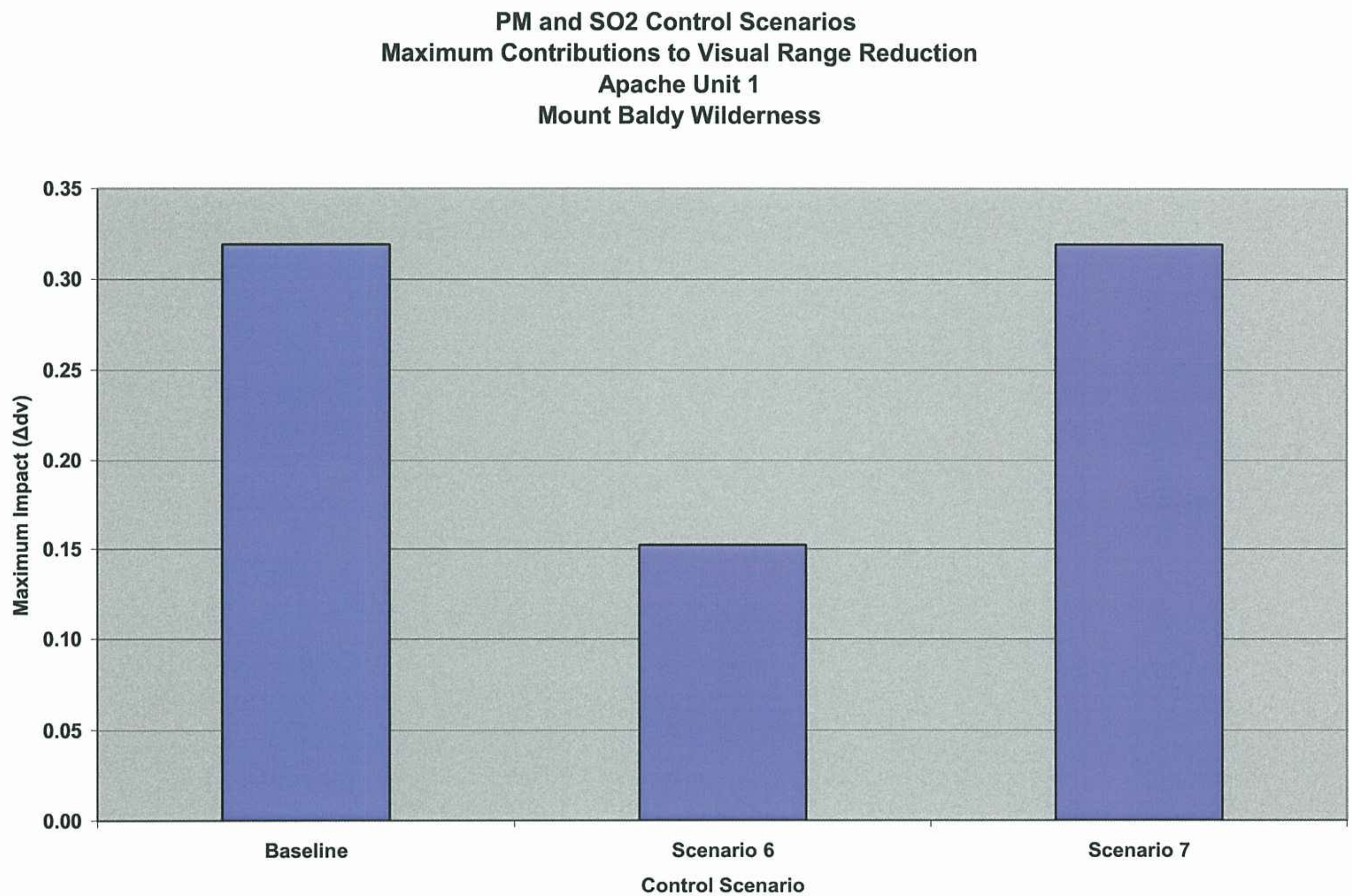

FIGURE C-18
PM & SO_2 Control Scenarios - Maximum Contributions to Visual Range Reduction at Sierra Ancha Wilderness
Apache 1

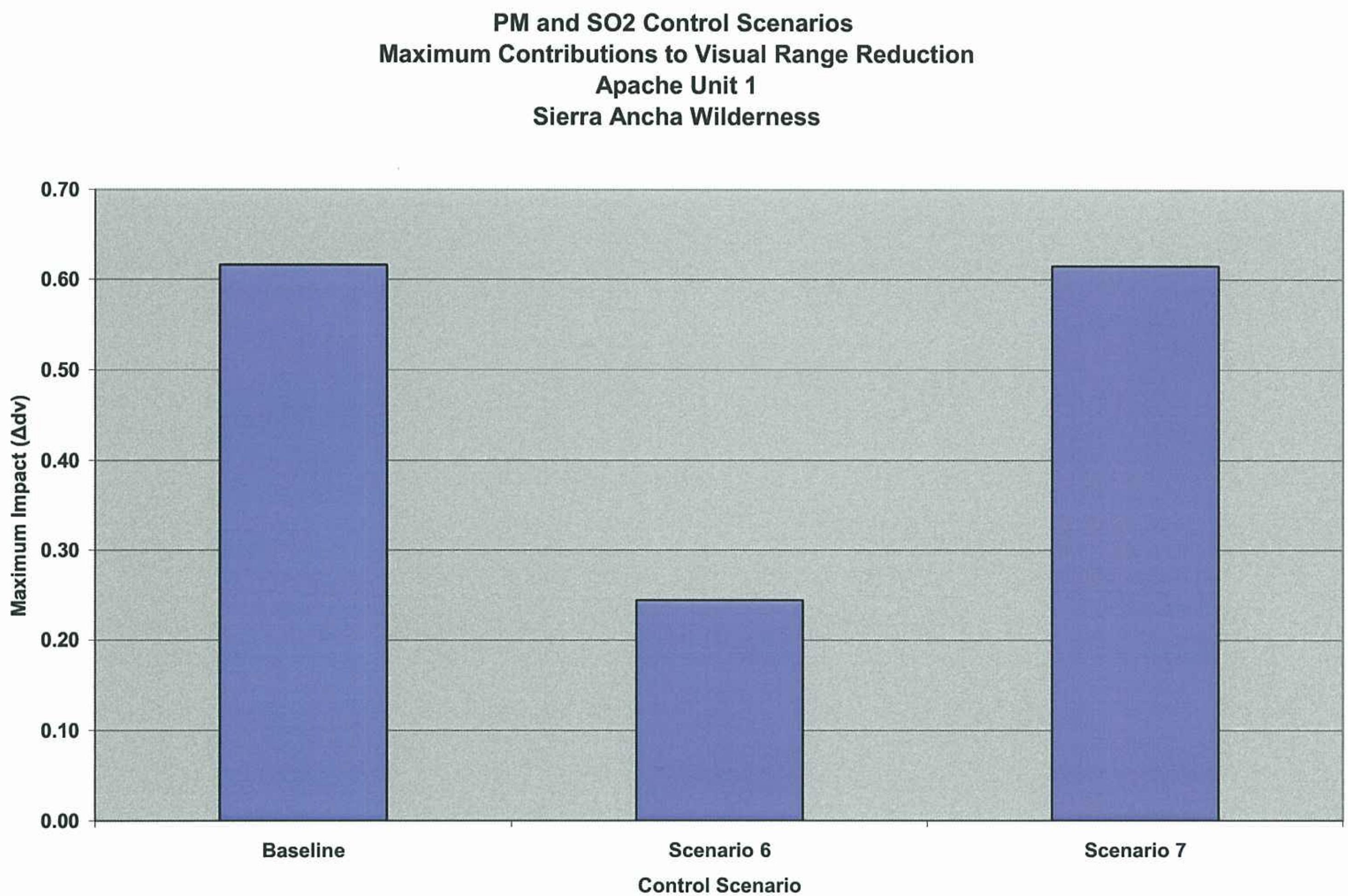

FIGURE C-19
PM & SO_2 Control Scenarios - Maximum Contributions to Visual Range Reduction at Mazatzal Wilderness
Apache 1

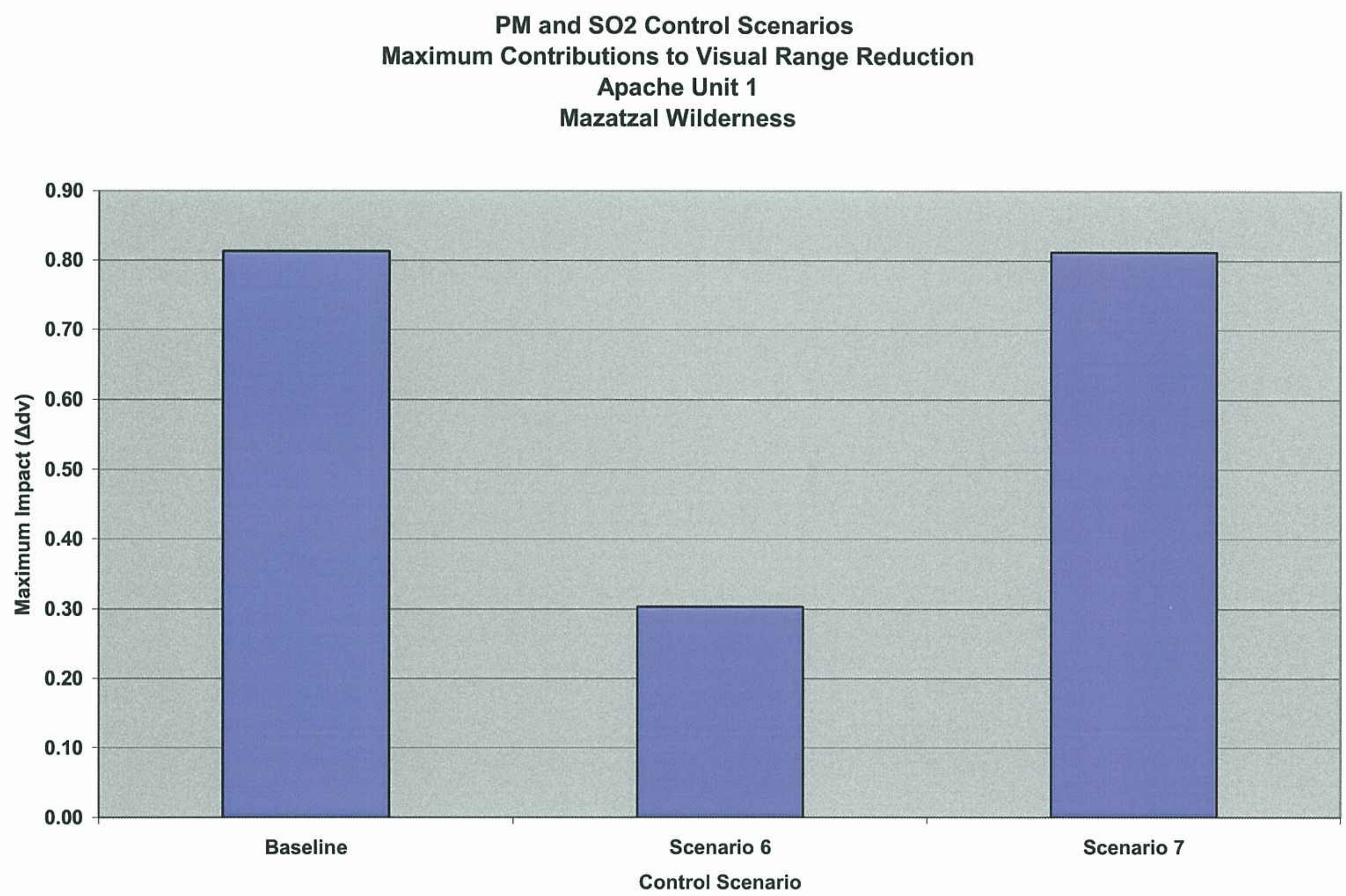

FIGURE C-20
PM & SO_2 Control Scenarios - Maximum Contributions to Visual Range Reduction at Pine Mountain Wilderness
Apache 1

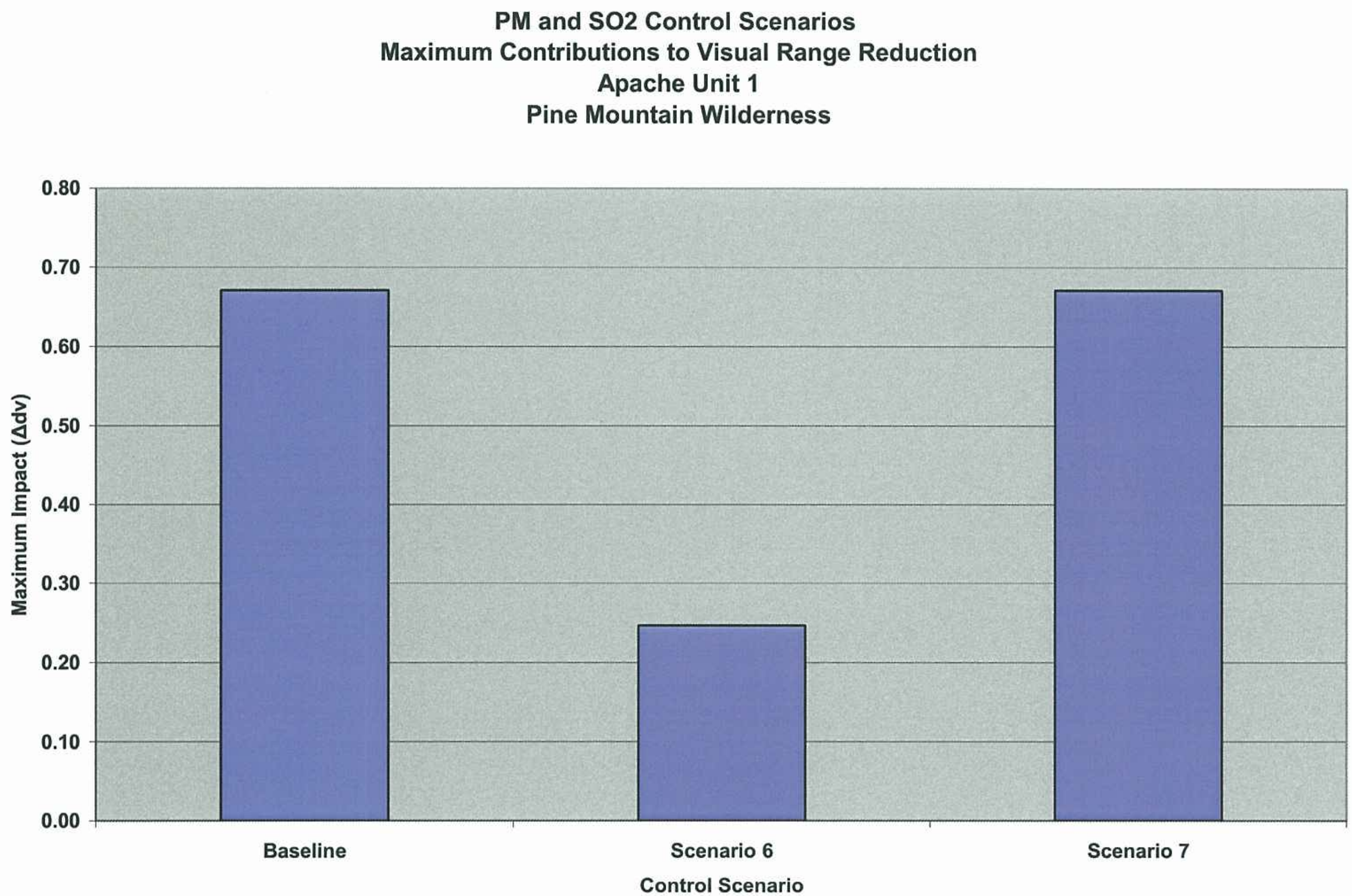

TABLE C-11
PM & SO_2 Control Scenario Results for Gila Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		0	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	0	0.142	7.498	NA	52.800
7	Fabric Filter	0	0.001	3.616	NA	3615.931

TABLE C-12
PM & SO_2 Control Scenario Results for Mount Baldy Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		0	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	0	0.077	7.498	NA	97.372
7	Fabric Filter	0	0.000	3.616	NA	NA

TABLE C-13
PM & SO_2 Control Scenario Results for Sierra Ancha Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	0	0.155	7.498	3.749	48.372
7	Fabric Filter	2	0.001	3.616	NA	3615.931

TABLE C-14
PM & SO_2 Control Scenario Results for Mazatzal Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	0	0.147	7.498	3.749	51.004
7	Fabric Filter	2	0.000	3.616	NA	NA

TABLE C-15
PM & SO_2 Control Scenario Results for Pine Mountain Wilderness
Apache 1

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		2	0.000	0.000	0.000	0.000
6	Fabric Filter/SDA	0	0.121	7.498	3.749	61.964
7	Fabric Filter	2	0.000	3.616	NA	NA

TABLE C-16
Gila Wilderness PM & SO_2 Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	0	0.142	7.498	NA	52.800

TABLE C-17
Mount Baldy Wilderness PM & SO_2 Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	0	0.077	7.498	NA	97.372

TABLE C-18
Sierra Ancha Wilderness PM & SO_2 Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	2	0.155	7.498	3.749	48.372

TABLE C-19
Mazatzal Wilderness PM & SO_2 Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	2	0.147	7.498	3.749	51.004

TABLE C-20
Pine Mountain Wilderness PM & SO_2 Control Scenario Incremental Analysis Data
Apache 1

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Scenario 6 vs. Baseline	2	0.121	7.498	3.749	61.964

FIGURE C-21
PM & SO_2 Control Scenarios - Least Cost Envelope Gila Wilderness - Days Reduction
Apache 1

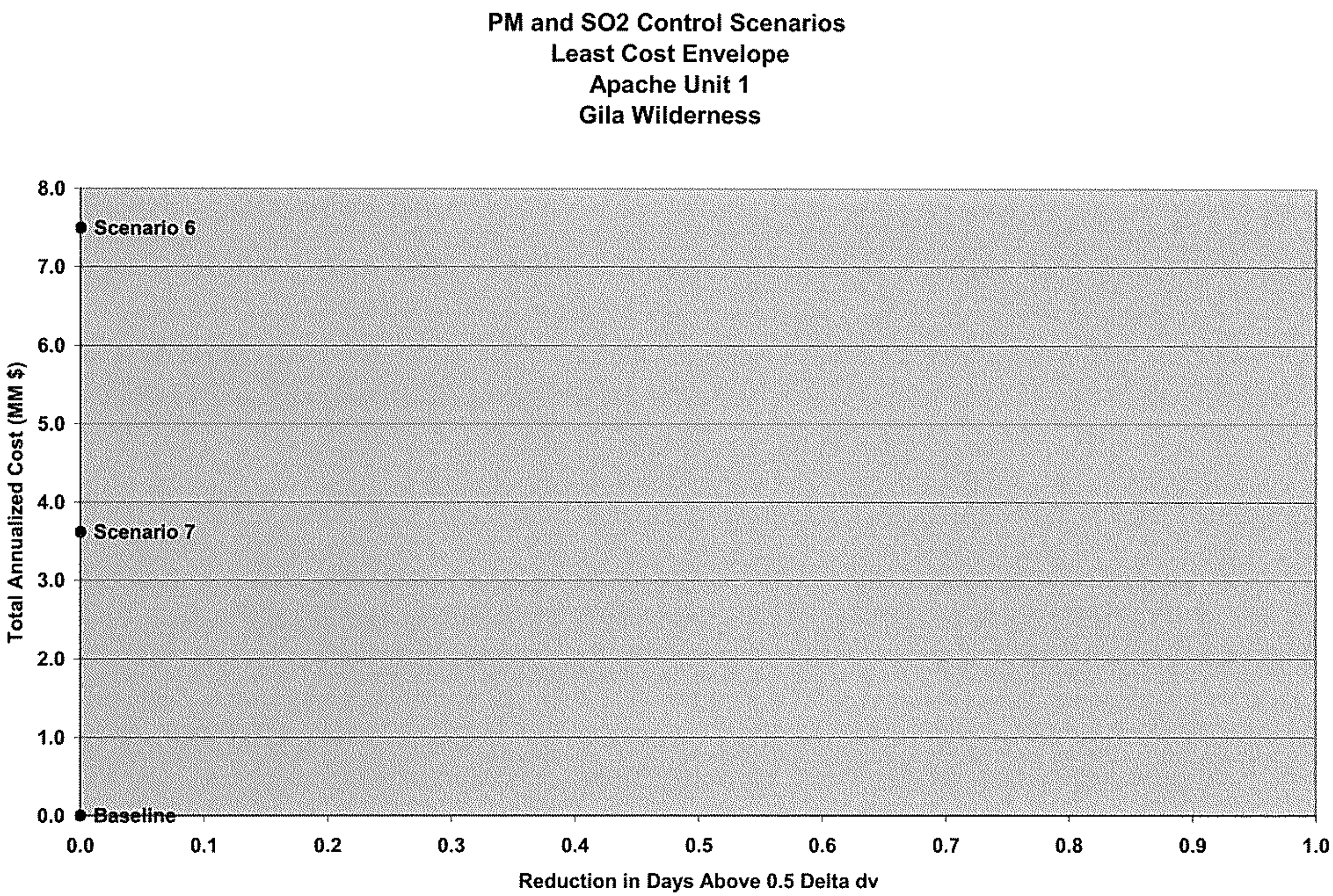

FIGURE C-22
PM & SO_2 Control Scenarios - Least Cost Envelope Gila Wilderness - 98th Percentile Reduction
Apache 1

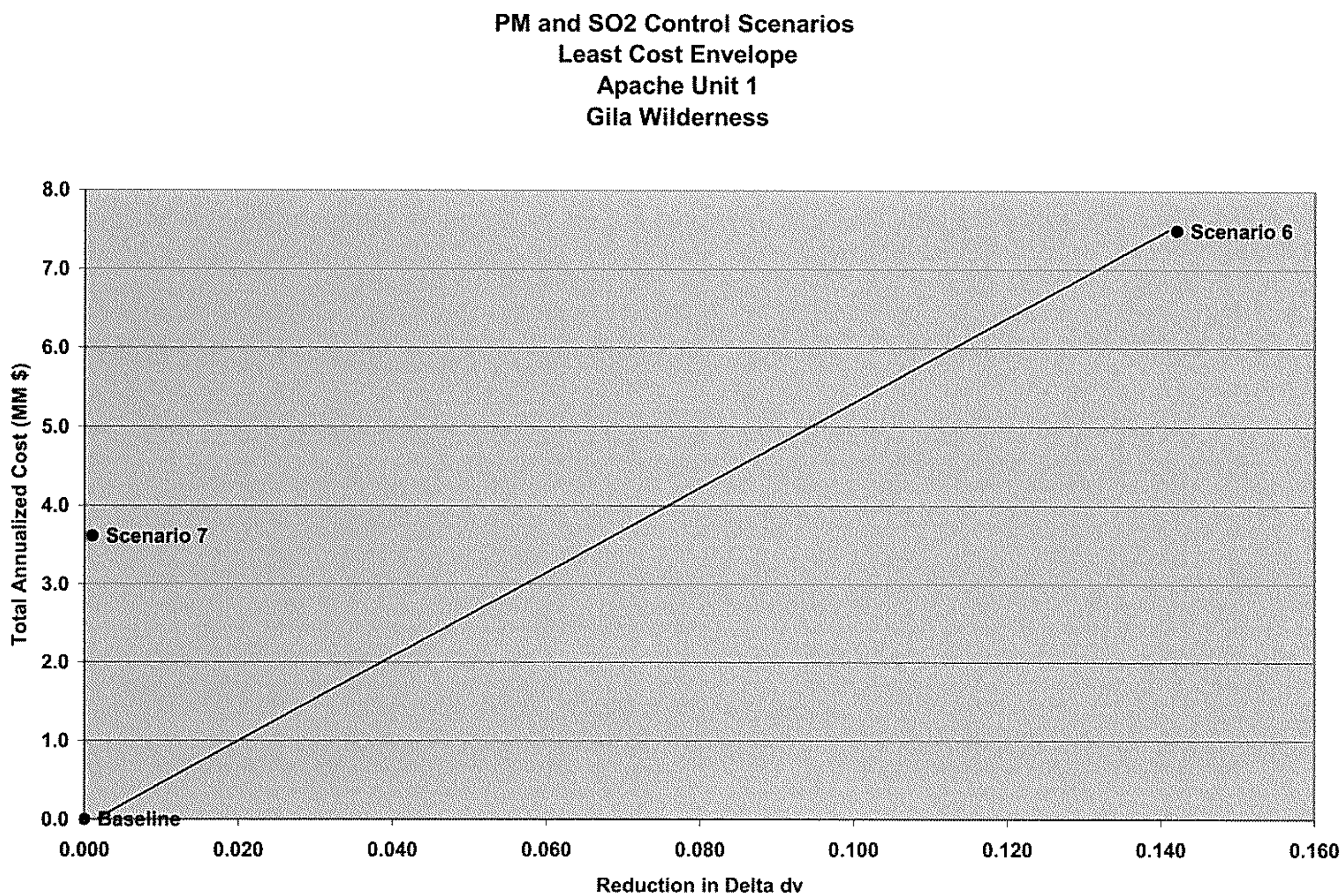

FIGURE C-23
PM & SO_2 Control Scenarios - Least Cost Envelope Mount Baldy Wilderness - Days Reduction
Apache 1

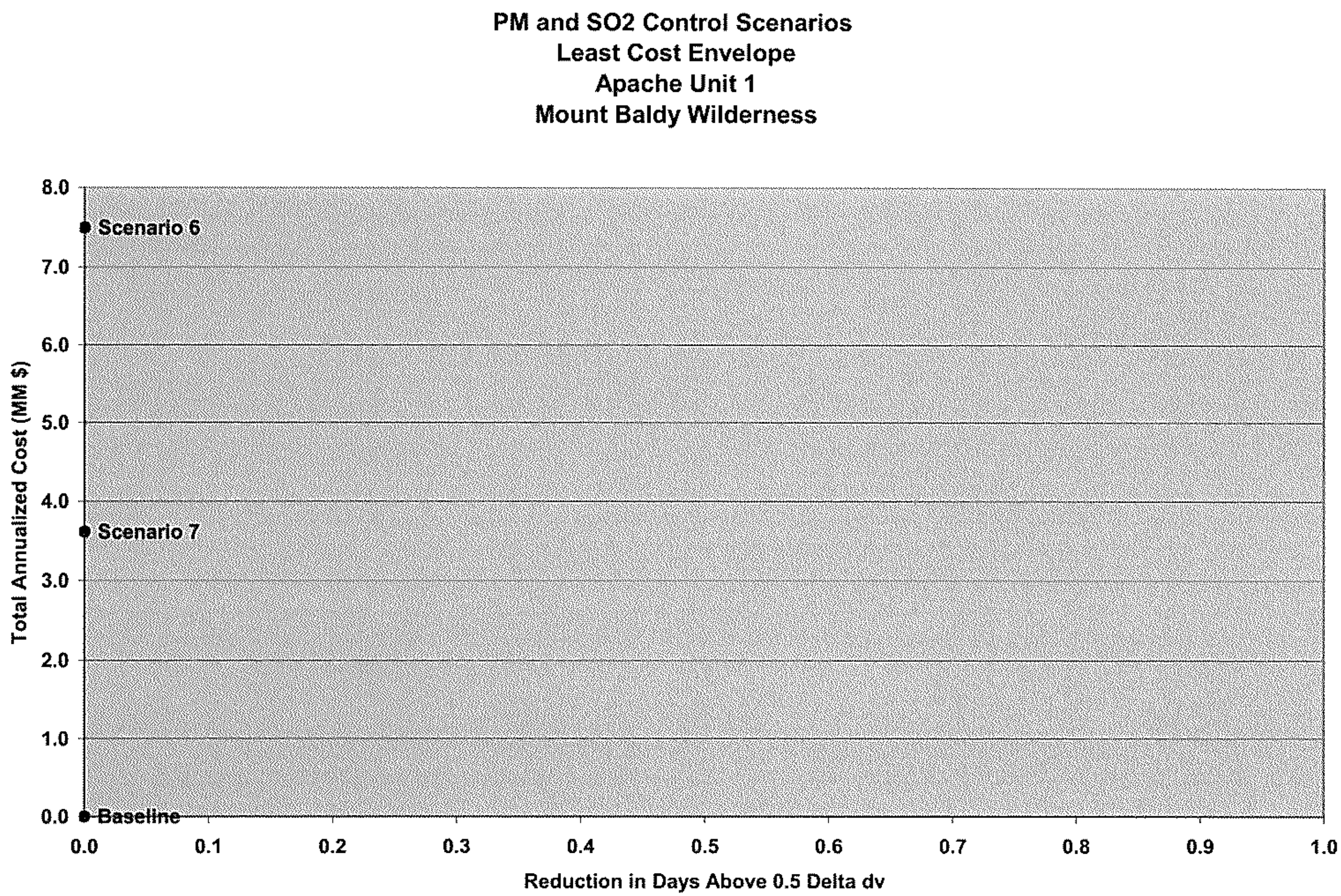

FIGURE C-24
PM & SO_2 Control Scenarios - Least Cost Envelope Mount Baldy Wilderness - 98th Percentile Reduction
Apache 1

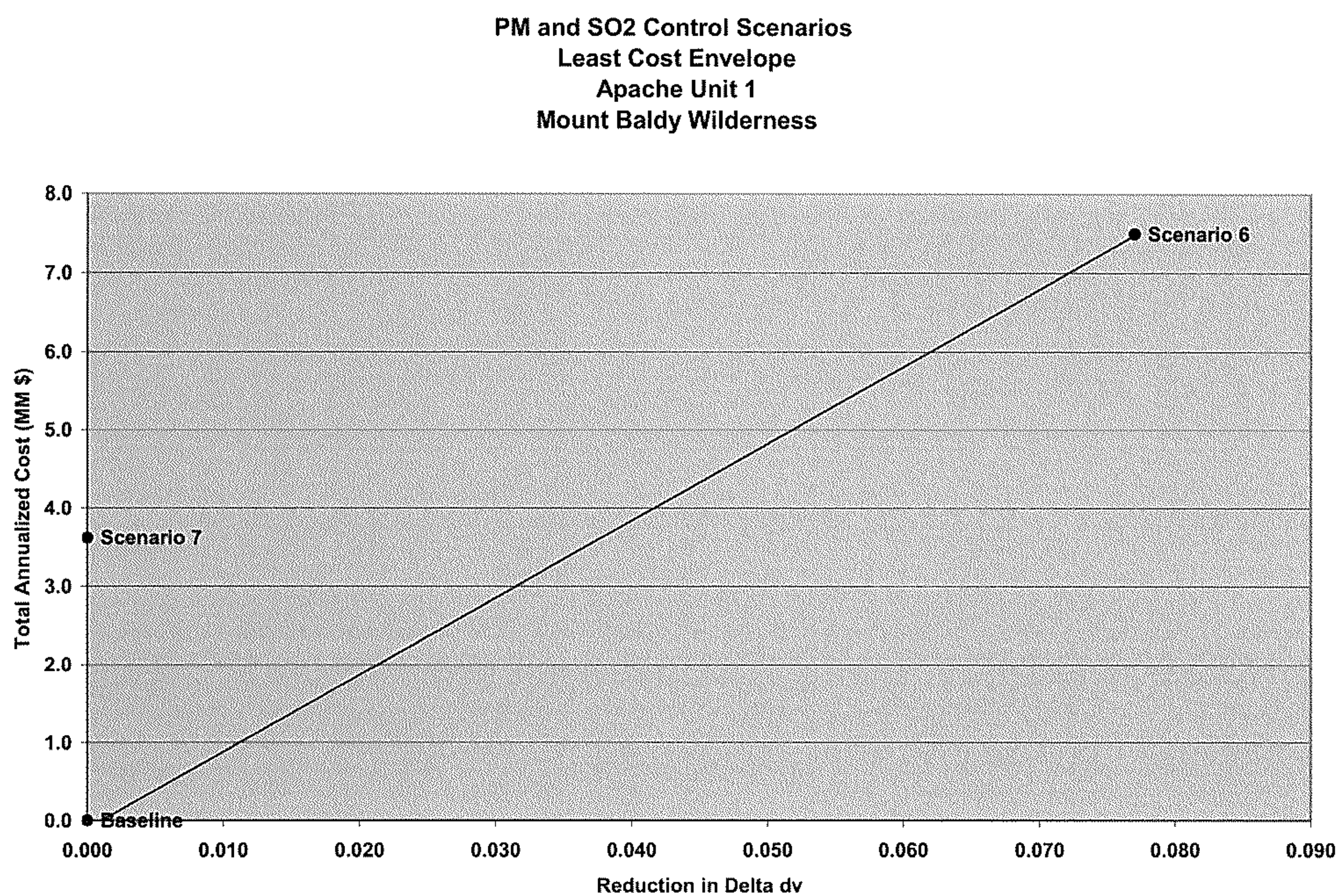

FIGURE C-25
PM & SO_2 Control Scenarios - Least Cost Envelope Sierra Ancha Wilderness - Days Reduction
Apache 1

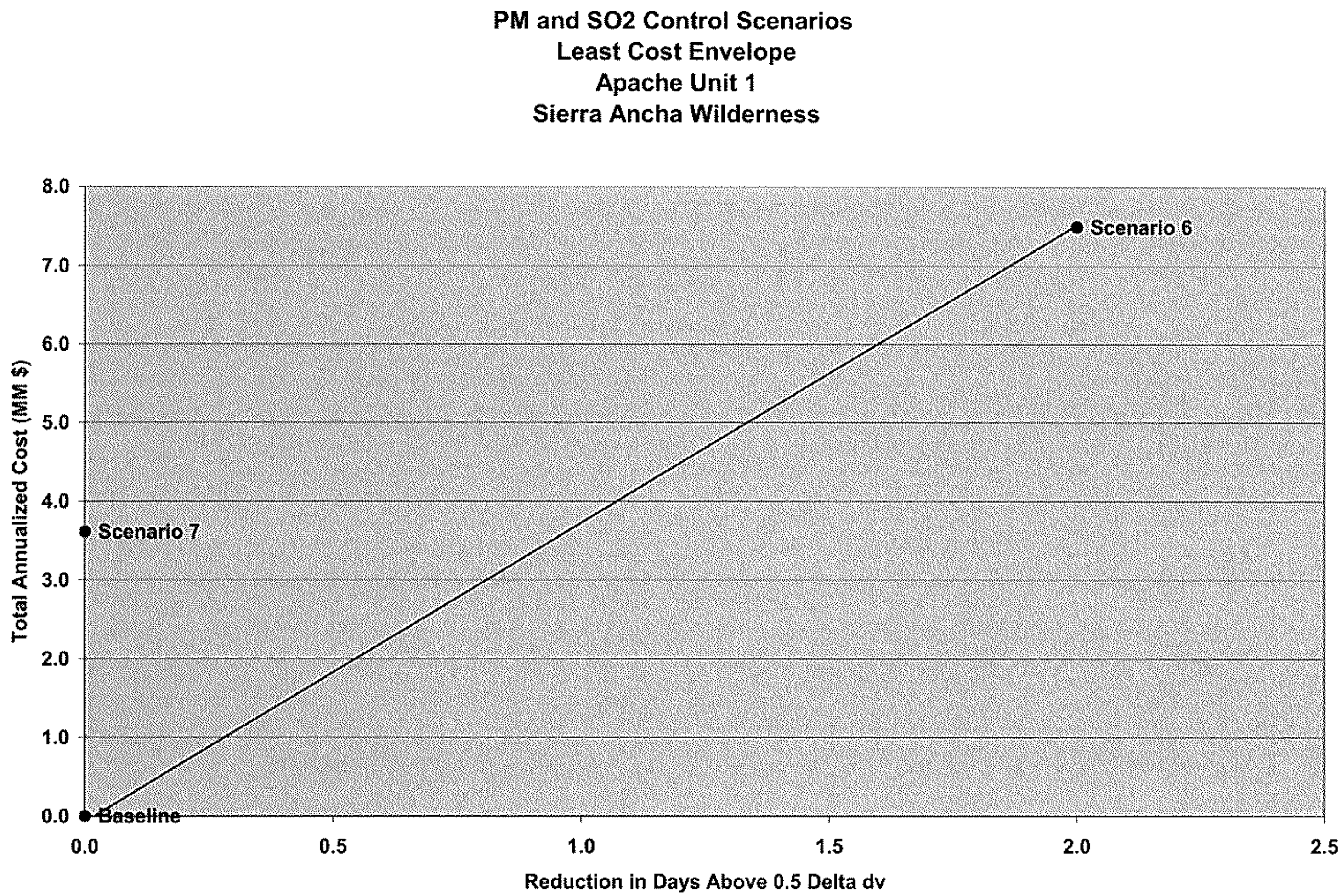

FIGURE C-26
PM & SO_2 Control Scenarios - Least Cost Envelope Sierra Ancha Wilderness - 98th Percentile Reduction
Apache 1

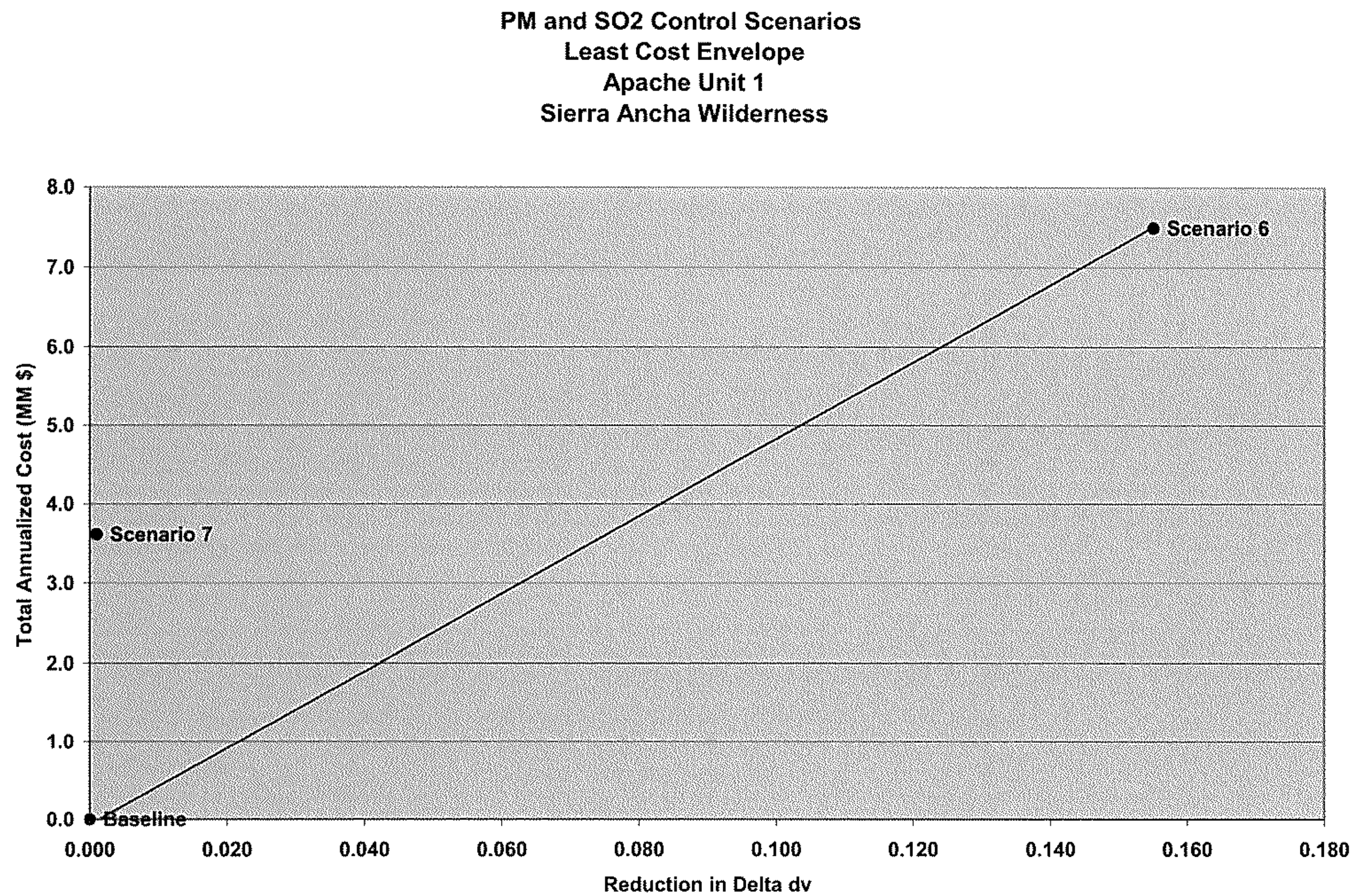

FIGURE C-27
PM & SO_2 Control Scenarios - Least Cost Envelope Mazatzal Wilderness - Days Reduction
Apache 1

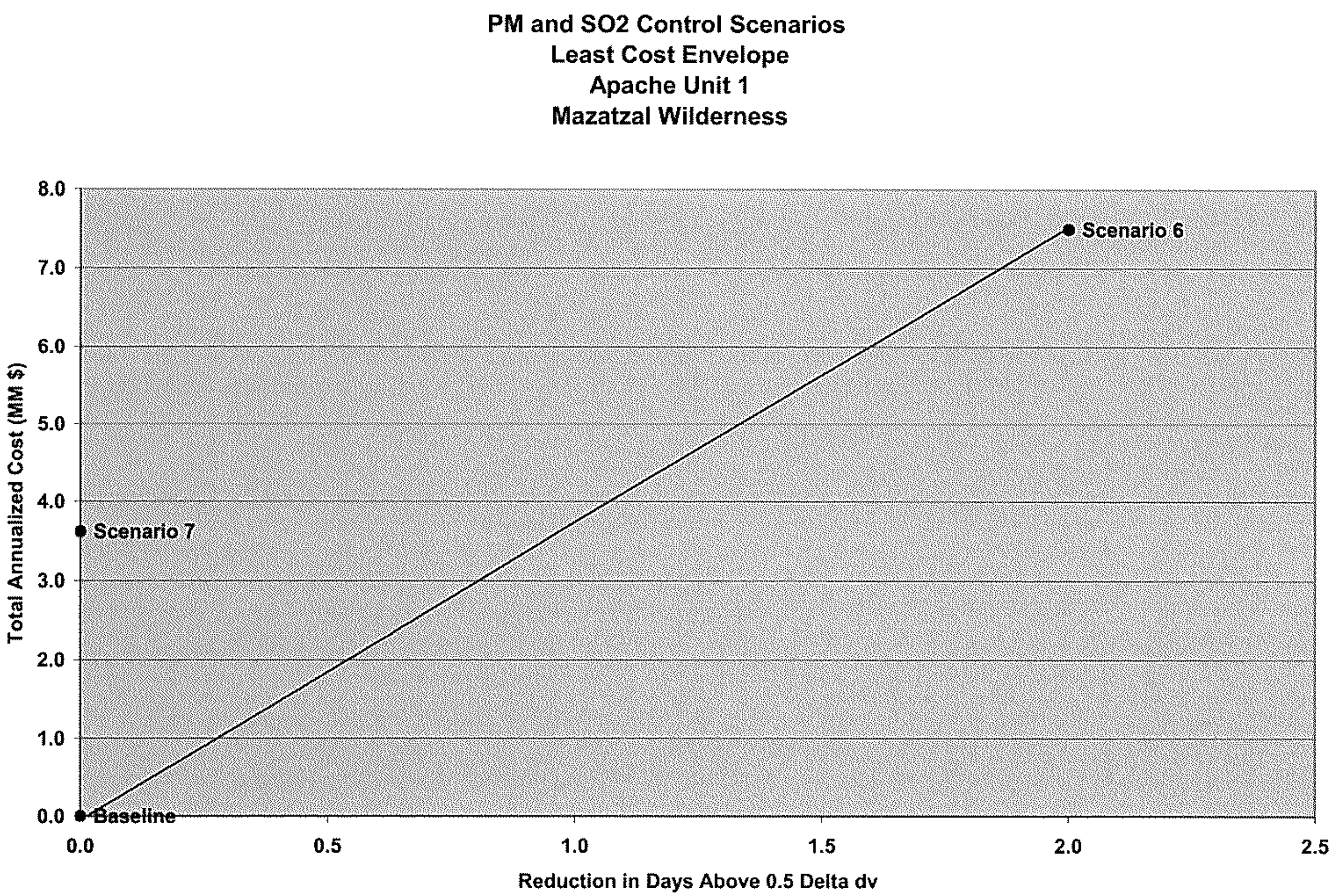

FIGURE C-28
PM & SO_2 Control Scenarios - Least Cost Envelope Mazatzal Wilderness - 98th Percentile Reduction
Apache 1

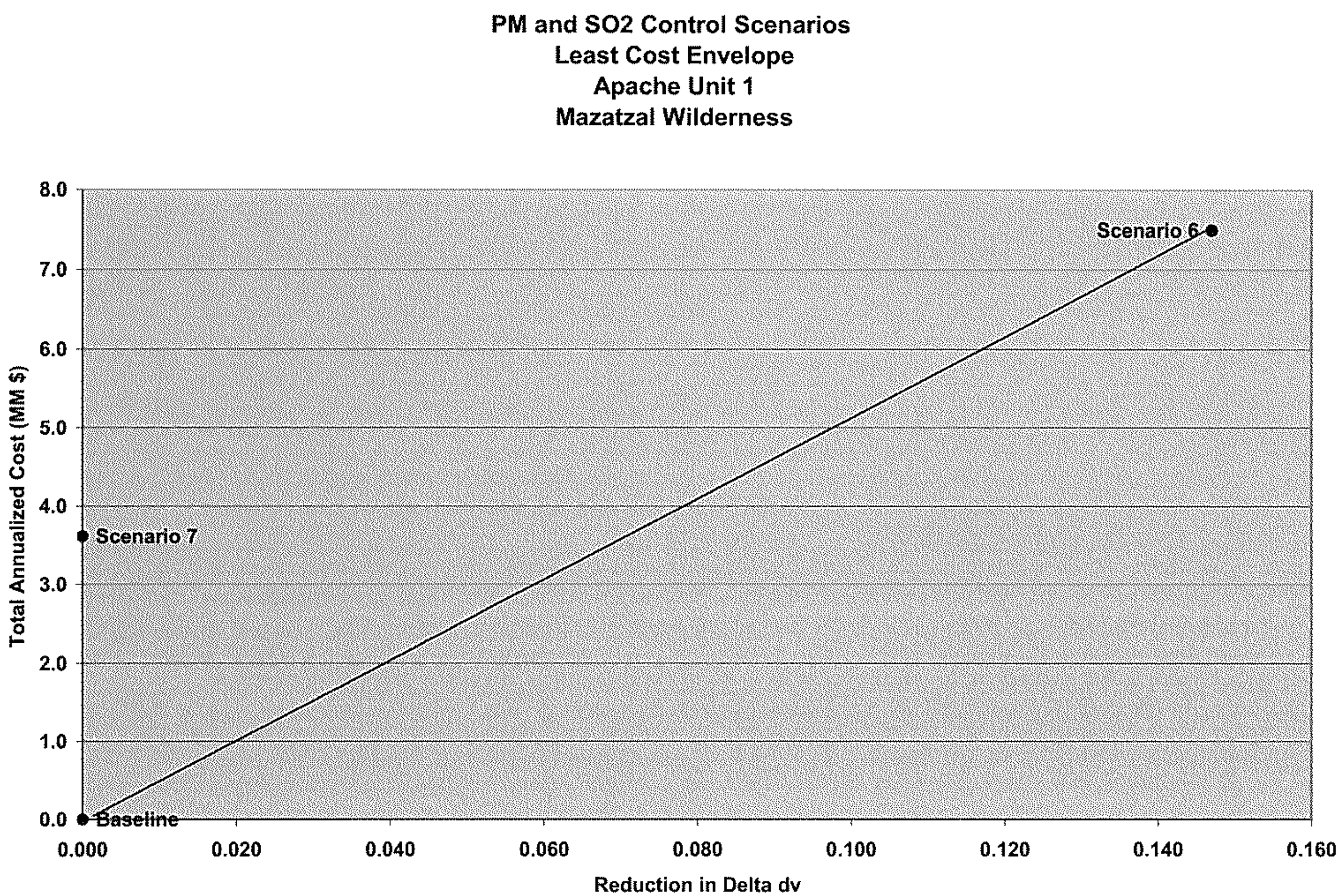

FIGURE C-29
PM & SO_2 Control Scenarios - Least Cost Envelope Pine Mountain Wilderness - Days Reduction
Apache 1

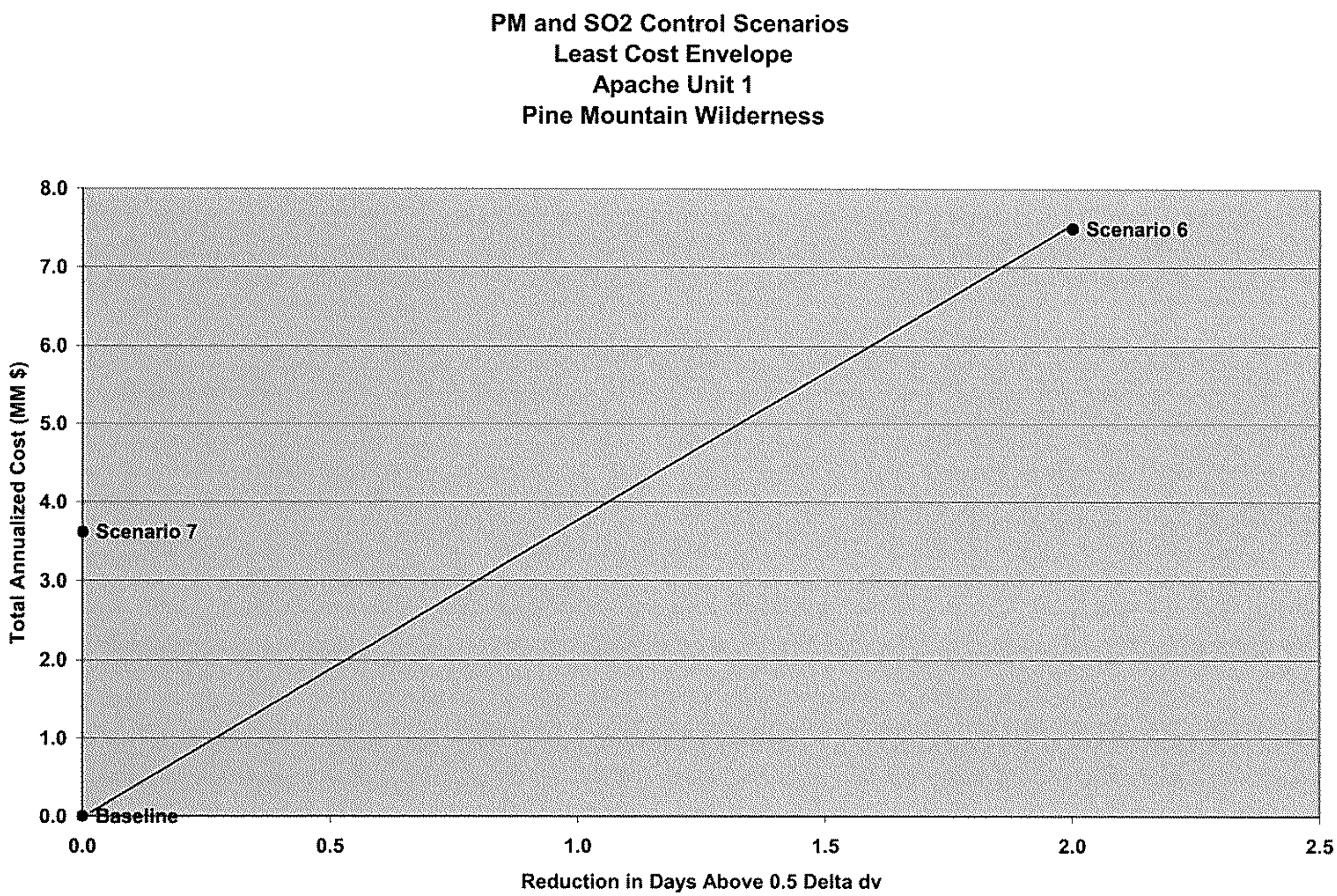

FIGURE C-30
PM & SO_2 Control Scenarios - Least Cost Envelope Pine Mountain Wilderness - 98th Percentile Reduction
Apache 1